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SAVING MONEY THROUGH STEAM AND COMPRESSED AIR MANAGEMENT 6

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SAVING MONEY THROUGH STEAM AND COMPRESSED AIR MANAGEMENT 6

Saving money through Steam and Compressed Air Management

Introduction:

Both steam and compressed air management offer the plant manager substantial potential for energy savings through a number of different types of conservation programs.

This booklet is largely devoted to effective operation and design of conventional steam and compressed air systems. Other information pertaining to boiler operation, production of steam from waste heat and other related subjects can be found in other booklets in this series. A cross referenced index to these subjects can be found in The Guidebook/Index.

Steam management

Steam is a conveyor of heat, and it was chosen many years ago for this purpose because of two basis properties: first, its ability to be generated from water which was easily available, and secondly, because it was able to store and carry a large quantity of heat at a temperature at which it could conveniently be used.

However, it now appears that the main quality which made steam valuable — its ability to carry heat — has led many people to take it for granted. Perhaps the fact that steam has been used for so long in industrial processes has given some of the bad habits regarding its use "grandfather" status in the hierarchy of plant practices; but, it is more likely that many engineers take its use for granted because so much of the heat in steam is *latent* or hidden.

One pound of steam at atmospheric pressure contains 1,151 British Thermal Units (Btu's). If there was no such thing as latent heat and if steam at atmospheric pressure was an ordinary gas to which 1,151 Btu had been added — it would have a temperature of 1,260°C. Would anyone ever waste steam at atmospheric pressure if it were a searing incandescent gas that would raise metals to white heat, and soften or melt all pipes and vessels? Not likely.

However, most of the heat in steam is latent. In fact, 971 Btu must be added to turn a lb of water at 100°C into one pound of steam at the same temperature. We cannot see this latent heat. We cannot feel it. So, in many cases, we waste it.

For many people in industry these facts are so rudimentary as to be unworthy of comment. Many companies have been aware of the precious nature of steam as an energy commodity for many years and have been actively working to conserve its use. But even these companies have become more receptive to energy conservation programes related to steam use in recent years as the cost of fuel used to generate steam has continued to escalate.

Now, more than ever, it is essential to have a steam system in a plant which operates efficiently and without unnecessary losses. Now, more than ever, it is essential that once water has been treated, heated, vapourized, and condensed in steam lines, that heat not be wasted by flushing condensate—at up to 100°C —down the sewer, or sending 100°C "flash" steam up a vent pipe.

Steam conservation is on the move. The following pages should help any company to climb on the bandwagon.

An efficient system.

A basic understanding of the operation of a simplified steam system is, understandably, fundamental to any attempt to conserve energy in this area.

The simplified diagram shows a steam system and gives an indication of a number of places where energy can be lost. Obviously, the first place to look for inefficiencies in a steam system is in the boiler itself.

Boiler efficiencies — the first link in the chain.

From basic principles, the efficiency of a steam generating boiler is its ability, as a complete system, to transfer the energy of the fuel burned to water and steam. This efficiency is dependent on the excess air of the burner and the heat transfer design on the boiler. The lower the

excess air and the better the heat transfer characteristics, the greater the efficiency of the unit. Other factors to be taken into account include boiler blowdown and preheating feedwater or combustion air.

Many of these topics are dealt with elsewhere in this booklet or in another booklet in this series (How To Save Money Through Combustion Control). But the burner is perhaps the most critical element to control the efficient use of fuel in a boiler and, it goes without saying, that a burner out of adjustment can waste large quantities of fuel.

Frequently, the following type of problem occurs: improper air flow to a burner, or a poorly adjusted burner, causes smoking because of incomplete combustion. The operator raises the total air flow to the furnace to control the smoking and meet air pollution standards — as a result, the excess air on the system goes considerably beyond the design point, and large amounts of fuel are wasted.

While gas burners do not generally require too much attention, oil fired units are quite sensitive to fuel changes. In fact, the viscosity of fuel oil must be maintained at a set level to permit sufficient atomization and proper air mixing. In addition, the fuel oil analysis should be reviewed frequently to ensure that the correct temperature is being maintained.

Burners are frequently sized by the manufacturer at the time of sale for a specific fuel analysis and a specific heat input, and if these fuel characteristics change, serious consideration should be given to modifying the existing burners or purchasing new ones. Attention to details like these will pay for itself many times over in fuel savings.

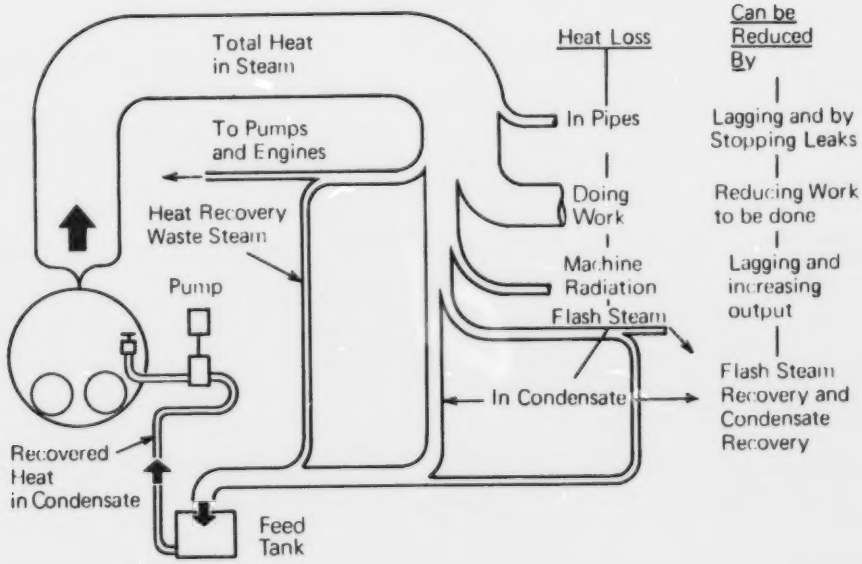
One way to minimize the number of man-hours which have to spent to assure maximum combustion efficiency is to install an up-to-date combustion control system. It's a step that could follow many others more basic in increasing the efficiency of the system, but where other lower cost measures have already been introduced, installation of sophisticated instrumentation and control hardware will help wring the last efficiency dollars out of a boiler system. Each plant application requires its own analysis, but in general, the return on investment and payback period from improved combustion control is very attractive.

Some plant managers consider combustion controllers economical only on large boilers (300-500 hp) and, on smaller boilers, rely on frequent analysis of flue temperatures and oxygen or carbon dioxide content.

Boiler tubes must be clean.

Moving further along the system, the heat transfer rate of boiler tube surfaces is an important consideration. Not unexpectedly, the amount of heat transferred by these surfaces varies directly with their cleanliness. Accumulations of fouling encrustations on

Where the heat goes in a steam system



internal or external tube surfaces will impair boiler performance.

While soot blowers are normally provided to clean the external (gas side) surfaces using the action of steam or air jets, their beneficial effects do not occur automatically. Blower operation should be scheduled on a regular basis and operators can be trained in the use of hand-held air or steam lances to clear slag or ash accumulations not removed by normal operating cycles of the soot blowers. Maintenance of the water side surfaces is also essential to long tube life and high efficiency. Here, the keys are proper feedwater treatment and scheduling of blowdown rates.

Boiler blowdown — a necessary heat loss.

Blowdown, of course, is required because when boiler water is turned to steam, almost all of the solids stay behind, and the level of dissolved solids concentration in the drum water must be maintained below a maximum level set by the manufacturer. Unfortunately, blowdown not only removes solids, it removes hot water and if excessive can result in significant heat losses.

The amount of blowdown required is directly related to the solids concentration of the feedwater and, as a result, properly treated feedwater is critical in maintaining blowdown at a minimum level. Returning condensate (discussed later), since it is free of solids, can make a real contribution to minimizing blowdown — not to mention reducing fuel consumption and treatment costs that would otherwise be incurred by heating city water to temperatures appoaching the boiling point.

Where compressor cooling water has been softened or treated as boiler feedwater, it too can make a significant contribution to reducing blowdown.

Some level of blowdown, however, must be accepted and continuous rather than periodic blowdown is preferable from the standpoint of controlling the associated heat loss. In addition, boiler water conditions should be checked twice each shift by a chemical analysis of the chloride content or by conductivity measurements.

Even if boiler blowdown is reasonably small, heat loss can be minimized using a blowdown heat exchanger or a blowdown flash tank.

A heat exchanger recovery system involves first the recovery of heat in the blowdown using a heat exchanger to preheat makeup water before it enters the boiler feedwater heater. In addition, a portion of the boiler blowdown is recovered as flash steam for use in the feedwater heater or for low pressure process or heating use.

The quantity of heat recovered in the heat exchanger can be calculated by a basic thermal balance analysis using the boiler blowdown rate, the characteristics of the heat exchanger and the temperature of the blowdown water — along with the average city water make-up rate and temperature.

The quantity of steam recoverable in the flash tank, on the other hand, is a function of the conditions of the blowdown water and the pressure of the flash tank. A chart is included which allows calculation of the percentage of liquid likely to be flashed to steam.

Another possibility for improving the efficiency of a boiler is to reduce the temperature of the flue gas leaving the boiler by using an air heater or economizer. The latter is a tubular heat exchanger used to cool boiler exhaust gases by heating the boiler feedwater. Many large utility boilers use both an economizer and an air heater, whereas in small industrial boilers one or the other but rarely both are found.

It is also worth mentioning that economizers are not normally used in low pressure boilers because the temperature difference between the feedwater entering the economizer and stack gases (94°C feedwater – 260°C gas) is less than the temperature difference for an air heater (26°C air – 260°C gas). An exception here are stoker fired boilers where ash problems and requirements to use combustion air to cool grates generally dictate the use of an economizer rather than an air heater.

After the boiler, heat containment is the challenge.

As soon as steam leaves the boiler, it immediately begins to try and give up its heat. The job facing an efficient system, then, is to assure that as little heat as possible is lost before the steam reaches the point at which the heat is needed.

In this regard, the first essential is that there should be no heat lost through direct steam

How much do leaks cost?

Size of leak (inches)	Air		Steam	
	Loss Per Month Cu. Ft. at 70 Psi. G.	Cost Per Month $ at $0.15/1000Cu. Ft.	Loss Per Month Lbs. at 100 Psi. G.	Cost Per Month $ at $3.25/1000 Lbs.
½	13,450,000	$2,020	500,000	$1,600
¼	3,360,000	$500	175,000	$570
⅛	840,000	$130	45,000	$150
1/16	210,000	$30	17,000	$60
1/32	50,000	$8	1,000	$30

leakage from faulty valves and joints. This kind of waste is both easy to detect and quick to consume energy and dollars. The chart gives estimates of the volume of steam that can be lost through holes of various sizes, but one graphic example is that in a 100 psig system, the steam leaking through a 1/32-inch hole will cost your company about $360 per year.

A considerable amount of heat can also be lost due to radiation from uninsulated steam pipes, and the facts here are even more staggering. A 10-foot length of uncovered 6-inch pipe carrying steam at 100 psig can waste 5 tons of coal or more than 650 gallons of oil a year. And it doesn't take a computer to see that a $300 or more loss can be compounded many times over by the longer length of pipe in a plant.

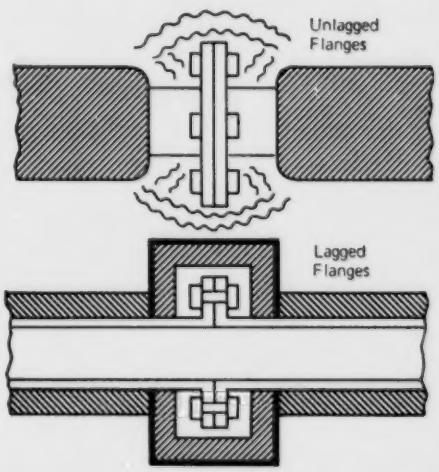
Many plants have insulated steam pipes over the years, but still experienced significant steam losses — whether they realized it or not. The source? — uninsulated pipe flanges. In fact, in many applications it has been common practice to stop an re-start the insulation 3 or 4 inches on either side of the flanges. There was an obvious reason for this practice — it made it easy to get at the flanges. But it should be recognized that uninsulated flanges are a source of considerable heat loss.

A ballpark assessment is that an uncovered flange represents the equivalent of leaving 2 feet of piping uninsulated. In other words, if 5 flanges are left uncovered on the 6-inch 100 psig line just mentioned, the equivalent of 350 gallons of oil is being wasted. The remedy? As shown in the diagram, flanges should be box insulated.

Nor does the problem of radiant heat loss stop there. Drying cylinders, steam chests, calender beds — in fact any process equipment where radiant loss is possible represent major consumers of energy. The rule of thumb here is that every square foot of uninsulated steam heated surface means, at 100 psig, a loss of about 820 Btu or approximately one lb. of steam per hour.

And the heat loss doesn't stop there. Heat from machines can make working conditions very uncomfortable, with the result that the operator opens a window to cool the shop. During the winter a cold draft blows over the machines and further increases heat loss.

Heat loss through unlagged flanges



Because of irregular shapes, not all process equipment is easily insulated—particularly where the equipment needs to be dismantled for maintenance on a regular basis. Insulation is, however, in a variety of forms and methods of application to enable both fitting of unusually shaped equipment and easy removal and replacement when required. A check with an insulation manufacturer or contractor will generally provide a solution to the problem.

In the rare case where equipment can not be effectively insulated without impairing some aspect of production or maintenance, aluminum paint is available that will give some protection against heat loss.

Why make steam work so hard?

Another major cause of energy wastage involves steam being made to do work which is unnecessary. Another booklet in this series ("How To Save Money Through Production Optimization") describes this situation in greater detail, and perhaps it is sufficient to say that in an ideal situation the plant should be shut down when not required.

Obviously, no plant will ever achieve a situation when the steam system is 100 percent utilized all the time, but to achieve real savings, it's a goal to shoot for. For example, a plant using 2,000 pounds of steam an hour, eight hours a day, five days a week when only 50 percent loaded wastes about 13,800 gallons of oil a year. That's $6,000 or more going up the flue.

Annual cost of heat losses from uninsulated steam pipes

Pipe size (in.)	Annual cost* (dollars)
½	300
1	1100
1½	1550
2	2050
3	2500
4	3650
6	4550
8	5650
10	7300
12	8500

*Note: cost per 100 feet of bare pipe.

Re-arrangement of process equipment, without interfering with production sequences can also pay handsome dividends by reducing steam loss—and the demand for steam—caused by straggling steam lines which have grown "like Topsy" over the years. The rule that equipment should be grouped as close as possible to the steam main is proven by the fact that even an unnecessary 10 feet of 2-inch pipe can waste $30 to $40 of fuel a year in a plant operating 8 hours per day, 5 days a week. This amount can be quadrupled for a plant which operates around the clock seven days a week. Insulation will, of course, reduce the loss by 70 to 75 percent, but it can not eliminate completely the waste caused by unnecessarily long steam distribution lines.

In this regard, splitting up the distribution system with suitable isolation valves will help, for example, by allowing one section of the factory to work overtime without maintaining steam in the pipes to other departments.

Another means of reducing the work to be done by steam is dealt with at greater length in the "Process Design" booklet in this series. In essence it involves making sure that processes are not operated at temperatures greater than those required to do the job well.

To cite an example, five open process tanks were operating at a temperature of 82°C, when it was known that 66°C would really do. The waste involved was an extra 11,500 gallons of fuel oil a year—more than $5,000 down the drain every year that could have been eliminated by a one time expenditure of less than $2,000 on temperature control equipment.

Lower pressures where possible.

It's a physical fact (and one readily determined by a quick look at one of the steam tables in this booklet) that the latent heat of steam decreases as the pressure rises. This means that the higher the steam pressure, the smaller the amount of latent heat (the most readily available heat) that will be available per pound of steam. Conversely, more pounds of steam at a higher pressure are needed to supply a given quantity of heat.

From the standpoint of steam economy, then, the lower the steam pressure, the lower the steam consumption for a given amount of heat

required. In addition, losses from leaks and traps will be lower. So it should pay to reduce the pressure in a steam system. And it does. There is an example in the case history of this booklet of a Canadian company which has done just this and saved dollars as a result.

The only bump in this otherwise smooth road to energy savings is that the lower the steam pressure, the lower is the temperature and, therefore, the lower the rate of heat flow from a given surface are (even though losses will be lower). Obviously what is called for under the circumstances, if pressure is to be lowered (or kept at the same rate and more work accomplished in a shorter time through greater heat available) is higher heat transfer in process equipment or any steam / heat exchange application.

On occasions, the amount of heating surface can be increased. For example, in heating system working at a pressure of 80 psig, by increasing the heating surface by 25 percent. In a room with four lengths of heating pipe, this would mean another length of pipe would be required. The resulting savings in energy use would average 4 percent per year.

Increasing the heating surface is a principle which should be borne in mind particularly when designing steam heating systems and when fitting heating coils in process tanks. But on a "retrofit" basis, in most process applications there is no opportunity to increase the heating surface. In these cases, the only avenue to improve steam efficiency at the extreme end of the system—and perhaps to allow a reduction in steam pressure—is a reduction of films and other barriers to effective heat transfer.

The diagram is very important in that it shows schematically the heating surface on any process steam application where the steam does not come into direct contact with the material being heated.

On the water side there is a stagnant film of the product (in this case water) and possibly a scale film of caked on product. These put up considerable resistance to the flow of heat to the product, but the effect of both can be negated quite successfully by regular cleaning or by mechanical stirring. Both are recommended and will pay dollar benefits.

Air-heat transfer's greatest enemy.

But where the problem is most severe and difficult to control is on the other side of the metal wall, on the steam side. Here there are three films: first, there is generally a scale film made up of rust and dirt from the pipes and of impurities carried from the boiler by the steam where feedwater treatment is not satisfactory or the boiler is under heavy load conditions. A periodic cleaning of this surface, regularly if possible, will reap tremendous improvement in heating efficiency.

Secondly, between the steam and the heating surface there are typically two more films. One of them is a water film—and water is a poor heat conductor. The other is an air film and represents the major barrier to good heat transfer.

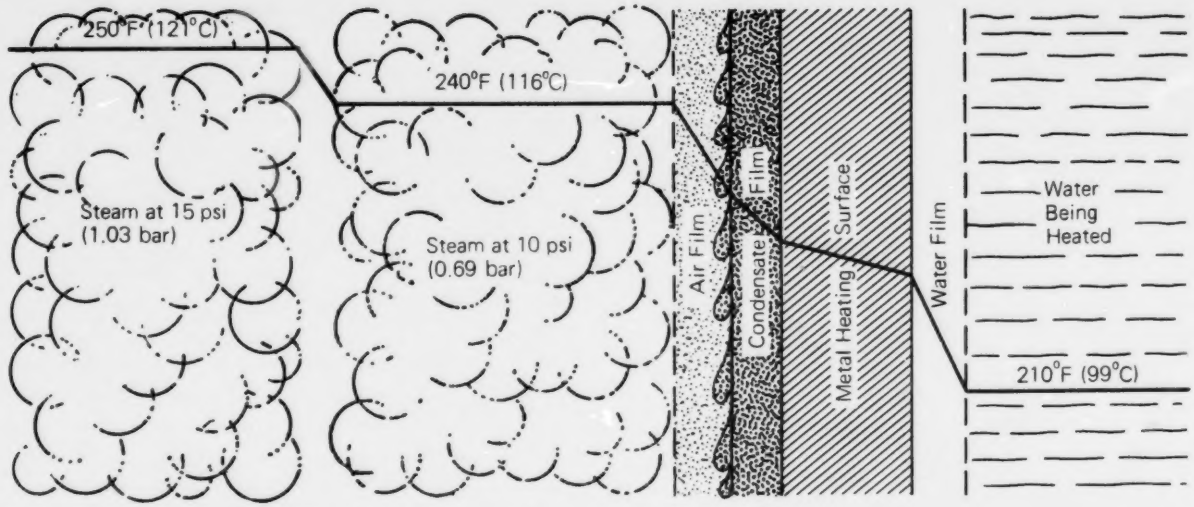
Water is bad enough. It is between 60 and 70 times more resistant to heat transfer than the iron or steel wall of the heating surface and 500 to 600 times more resistant than copper.

But given that among insulating materials the most effective insulator is the mass of minute air cells enclosed by non-conducting fibres, it should come as no surprise to learn that air is more than 1,500 times more resistant to heat transfer than iron or steel and no less than 13,000 times more resistant than copper. This means that a film of air only 1 / 1000 inch thick will resist heat transfer as effectively as a wall of copper 13 inches thick!

The practical effect of air and water films on process output is shown in the diagram. By reducing the thickness of the air and water films, steam pressure can be reduced a full third from 15 psig to 10 psig while still achieving the same required process temperature of 98°C.

Obviously, on all process applications, the thickness of the films on the condensing surfaces must be reduced. In fact, in the case of the air film, a number of other problems other than reducing heat transfer result. Air causes a reduction in steam temperature below that of undiluted steam and can gather in pockets in process equipment where the cross section of the steam space is realtively small — and as a result cause cost spots on the heating surface.

All of these problems eat into the efficiency of the



The effect of air and water films on heat transfer

plant equipment and, in the end, increase energy consumption.

The solution? For the air film the answer can be use of balanced pressure air vents which have a thermostatic characteristic which allows air steam mixtures to escape but which close in the presence of steam and are not affected by variations in steam pressure. Although some companies have encountered maintenance problems and eventual steam leaks. As a maxim: "A good trap will remove air in a well designed system".

Because the position of the steam inlet and the shape of the steam space have an important bearing on where air will be deposited, it is not possible to lay down any hard and fast rules about the positioning of air vents. A knowledge of the shape of the steam space and a number of other factors will help, and a consultant or supplier will certainly be able to provide needed answers. The choice of steam traps based on ability to handle air may also be involved.

Water — a difficult foe.

The challenge with the condensate or water film is one of a different order. When "dry" steam comes into contact with the surface to be heated, it gives up its latent heat and condenses — forming the insulating film. If the steam is wet, that is, contains fine droplets of water, this water is deposited on the heating surface, increasing the insulating film but contributing nothing in the way of latent heat.

The fundamental solution is to improve the dryness factor of the steam as it leaves the boiler, by eliminating peak demands and overloading of boilers where possible, and by careful attention not only to boiler treatment chemicals but to the way they are applied.

However, the very nature of steam generation under commercial conditions makes it impractical to avoid some carry over of water particles in steam — and more water is necessarily added by the steam as it passes through the pipe system.

Here, it is critical that steam be taken at the top of the main line and if the line is well drained, dry steam should be available. In any heat exchanger, the slope of the pipe will be critical in eliminating water quickly.

Steam traps — a culprit that needs attention.

It's no news that when steam gives up its latent heat, it condenses and must be removed from the lines using steam traps, to allow steam to make good contact from heating surfaces.

One case history in this booklet deals in some depth with an organized approach to steam trap maintenance and will be of interest to anyone who wishes to pursue the subject in greater depth. Suffice it to say, selection of the right steam trap and locating it in the best position is important as is the use of strainers in front of the traps to prevent accumulating of dirt and foreign material in the traps themselves — a leading cause of traps "blowing steam".

Sight glasses in the line after the traps can be useful in detecting leaking steam traps, and thermal tapes which change colour at temperatures above the condensate temperature can be of assistance, but the operative word as far as energy conservation through steam trapping goes, is *MAINTENANCE* — regular inspection of steam traps and replacement where necessary will pay for itself every time and should be a major priority in every plant with a steam system.

The condensate, which is collected by steam traps along the line, still contains a significant amount of sensible heat and if simply directed to the sewer, will carry a significant amount of heat and dollars with it. Some plants manage to recover more than 90 percent of this condensate as boiler feedwater. For these plants, it represents a source of hot, pretreated water. In short, it's a valuable commodity.

In many cases these plants are in areas where there is not an abundance of fresh water. The energy that was being wasted was really not a factor. As a result, many other plants where water is available, have a very low recovery of condensate. But the ground rules have changed over the past few years and given today's energy economics, it simply makes sense to maximize the recovery of condensate as boiler feedwater.

But before condensate can be used for this purpose, it must be discharged from the steam line to the lower pressure of the condensate return line. And high temperature condensate can not completely remain as water — the excess heat allowed by pressure re-enters the water as latent heat forming "flash" steam.

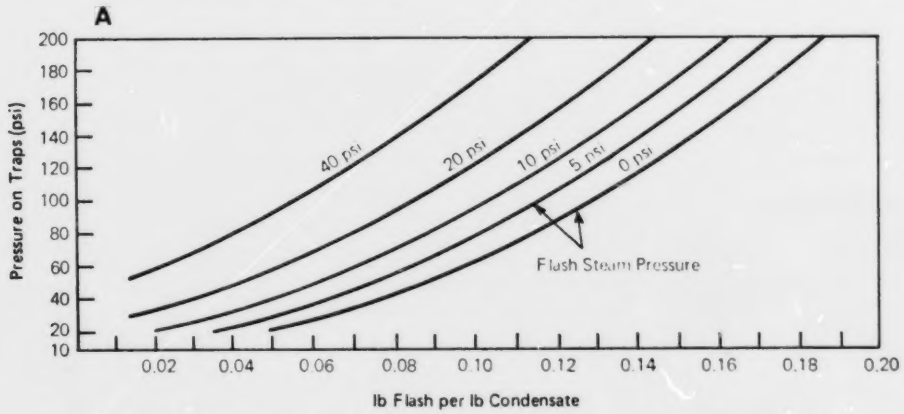
If the condensate is collected in a return line at atmospheric pressure, the flash steam will generally condense, forming condensate at 100°C, but the latent heat of the flash steam will have been wasted.

However, if the condensate can be discharged to equipment merely working at a lower pressure, much of the flash steam can be recovered and put to use. The chart on this page shows the amount of flash steam generated when condensate at different pressures is discharged to a heating or process system at a given pressure. For example, when condensate at a pressure of 200 psi is discharged into a 10 psi system, flash steam amounting to 16 percent of the condensate will be found.

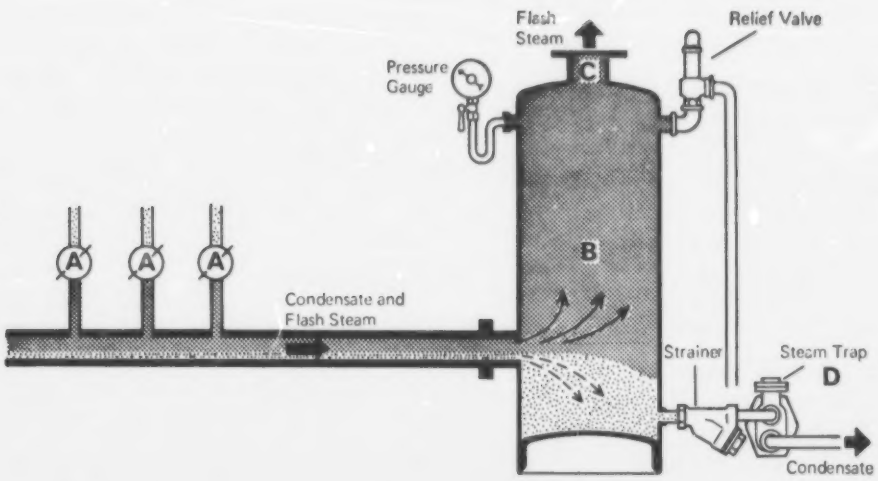
Flash steam and condensate recovery-related subjects.

In most industrial applications, condensate from various pieces of equipment is discharged into a common condensate line back to the boiler feed tank. The condensate pipes are often not insulated and the feed tank uncovered or sometimes an open tank vented to the atmosphere, with condensation return delivered above water level.

Flash steam formed at traps travels with the condensate along these return lines. If the pipes are uninsulated, much of the steam will condense as outlined before, and the heat will be radiated to the air. If the pipes are insulated, a good deal of steam will reach the tank and if the condensate return is above water level, much of the flash will escape to the air. If the return is below the water level and there is a considerable proportion of cold make-up water, some of the flash will be condensed and the temperature of the feed raised.



Quantity of flash steam available at various operating conditions



A typical flash vessel in operation

If all precautions have been taken to conserve heat in the condensate, a major question must be asked. Will the feed pumps handle water at the high temperatures involved? In most situations, the better solution is to put a flash vessel either in the common condensate return line or in after the traps on large high pressure steam using equipment. The flash steam given off here can then be taken to a low pressure steam system or unit.

As shown in the diagram, condensate at high pressure passes through the traps to the flash vessel which is at a lower pressure so that some of the condensate flashes to steam as it leaves the traps. The flash steam is led away and the condensate drained by a float type trap with continuous discharge.

Under the ideal circumstances, flash steam should be used where there is a continuous demand for all the flash steam available and where maximum heat recovery can be attained by keeping pipework to a minimum. This generally leads to a number of small self-contained recovery units rather than one large unit. And obviously, both the flash unit and connecting pipes should be well insulated.

Heating systems often offer good opportunities to take advantage of low pressure flash steam. The hitch is that while low pressure steam has a higher latent heat content, it also has a lower temperature (total heat content) requiring larger pipes, unit heaters and other heating surfaces.

Generally, the most happy solution is to use a combination of high and low pressure steam for heating. If a plant consists of, say, five bays, it makes good sense to heat four bays with high pressure steam from which flash steam is recovered to serve the fifth bay at low pressure.

However, there are many process uses for low pressure steam as well, and it is well worth while to look for them around the plant. Use of low pressure flash steam can considerably reduce demands on the main boiler and in so doing, save considerable amounts of fuel and dollars. In some cases, it can even do away with the need for additional main boiler capacity. Much written material is available to help with such factors as flash steam pressure and the size of the flash vessel. A consultant with specific expertise in the area may also be necessary. But whatever is done to recover flash steam, chances are it will be worth the investment.

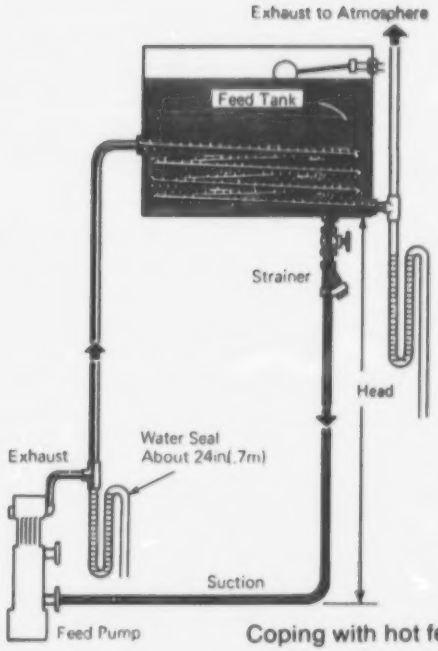
Condensate — too hot to handle?

It was mentioned earlier that without flash steam recovery, condensate could be too hot for pumps to handle in moving into the feedwater tanks. In those cases where sufficient static head does not exist over the pumps to handle the hot condensate, think of installing an auxiliary feed tank at a higher level. As shown in the drawing, condensate from the existing hot condensate tank can easily be raised to the new high level using a pumping trap — an automatic device in which a float, responding to the level of incoming condensate, opens a boiler pressure steam valve and flows a charge of condensate to the higher level. A pumping trap is not large and consumes very little steam.

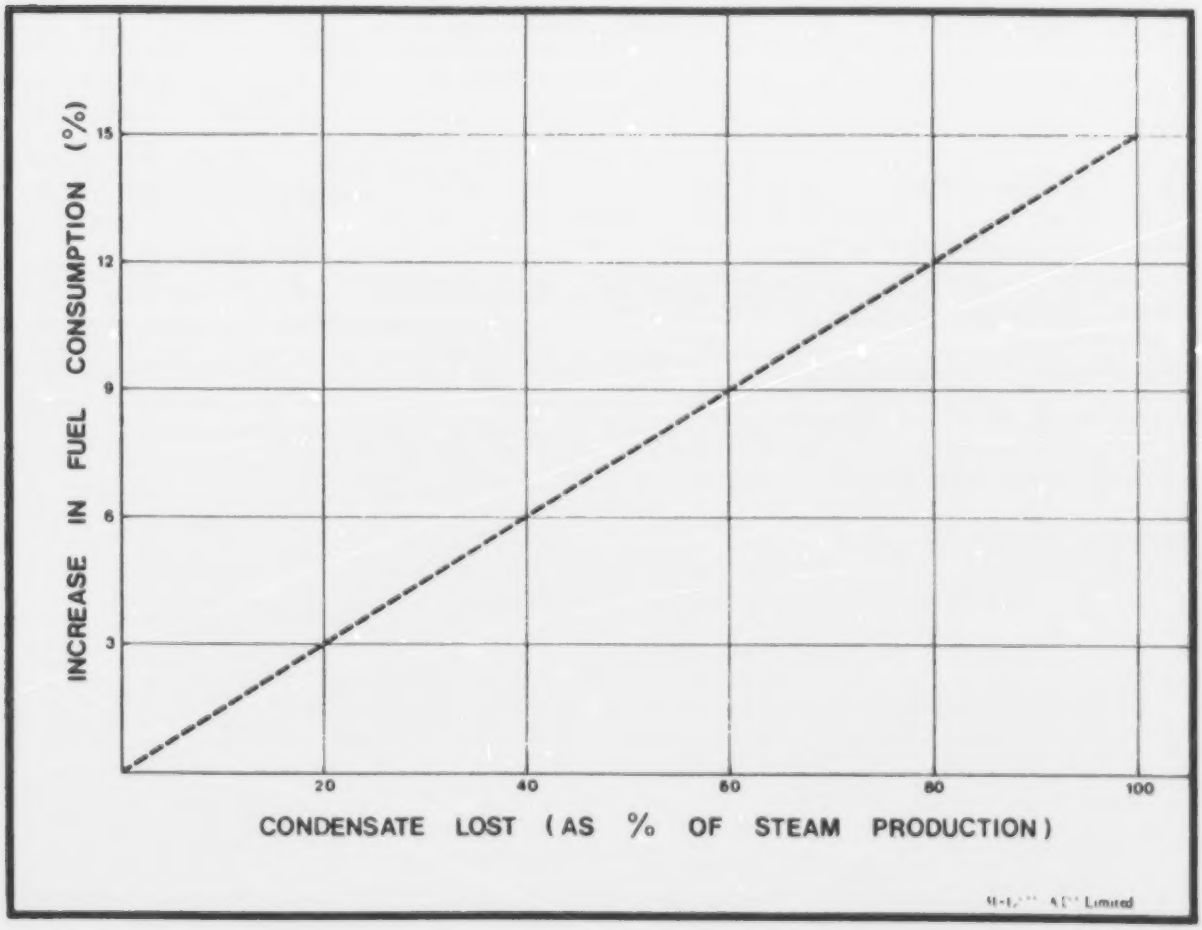
Condensate then can be handled by some means, whatever its temperature, when returned to the collection tank. But perhaps, some general comments are in order about the desirability of making sure that this condensate is captured and used as boiler feedwater. The graph plots percentage of condensate lost against the resulting increase in full consumption.

As a general rule, every 7°C rise in the temperature of the feedwater results in approximately 1 percent less fuel being burned in the boiler. And don't forget that to this saving must be added the economies derived from the reduction in water consumption and treatment chemicals or process requirements!

As mentioned earlier, condensate lines should be well insulated — as should the feed tank itself. In fact, both insulation on the bottom and sides of



Coping with hot feedwater



a tank and a cover are well worth the investment. The diagram demonstrates this point quite graphically.

Frequently, condensate is not returned to the process tank because it is thought that equipment is too far away. As a result, the economics appear, at first glance, to be poor. As with most energy conservation investments, this is generally a poor assumption to make. A careful analysis of the one-time costs versus the long term savings generated will almost always justify the cost of piping.

Other uses for condensate.

Even if the cost of returning condensate to the boiler should prove to be prohibitive, there is no point in disposing of it in the sewer. Washing or other processes can always use preheated clean water and will produce direct dollar savings comprised of both the cost of water and the energy which would have been necessary to heat it.

But the operative word in the preceding sentence was "clean". And it is essential that the condensate not be contaminated when it is returned to the boiler. Oil from engine exhausts, material from processes, iron from cold lime treated makeup water and a number of other contaminants can find their way into condensate. But there are ways to reduce this contamination. For example, repairing the break in steam coils will generally remove product contamination and neutralizing or filming amines injected into the steam will reduce iron pickup in the condensate return system.

But, again, if the economics of the operation do not justify the de-contamination of the feedwater (and this is rare), consider the heat value of the condensate and make use of it in some fashion. Send it to the sewer only as a very last resort.

To cite one possibility, a simple heat exchanger where a bath of hot (and perhaps corrosive) condensate is used to heat feedwater running through a coil of pipes, can be an efficient low cost means of recovering heat from the condensate if it can be used for no other more profitable purpose.

Steam tracing — a savings opportunity.

It goes without saying that use of steam for tracing systems to prevent liquid piping from freezing in cold weather represents another important area which should be considered in planning an energy conservation programme for your plant. While the potential dollar savings are not as large because the volume and pressure of steam used is generally considerably lower, it is an area which deserves attention. And for the most part, techniques used in process and steam heating applications can be applied directly to steam tracing applications.

And maintenance is again the watchword.

As a basic assumption, winter tracing should not be used until necessary and should be turned off during the summer (it is surprising how many systems are left on through the hot weather). It goes without saying that traced lines should be equipped with appropriate traps and insulated as well as possible. Preventive maintenance on the traps and frequent checks to make sure that they are not "blowing steam" will also result in significant savings.

Perhaps two relatively new techniques warrant singling out for special mention. The first of these essentially displaces steam in tracing applications and can offer substantial savings on maintenance and fuel costs. It involves the use of a specially inhibited ethylene glycol/water solution—with a freezing point of − 36°C in place of steam to heat tracing lines. While these systems are only economically applicable in plants with major consumption of steam for tracing, they involve only one steam trap — on the heat exchanger which heats the solution in a tank before it is pumped through the tracing lines — and can achieve steam savings of 1,000 pounds per foot of tracers per year.

One plant in the United States cut its steam consumption for tracing in half by converting to an ethylene glycol heat transfer medium system. And although additional electricity was required to pump the solution through the pipes, the net savings was still in the neighbourhood of 40 percent — with the investment required for conversion almost entirely recovered in the first year of operation.

The second energy conservation measure is nothing new in concept. It involves the shutting off of steam to tracers during weather where steam is not required. The difference here is that it can be done automatically by a temperature activated control valve which opens fully at

atmospheric temperatures under 1°C and fully closes at temperatures over 4°C. These valves are a low cost substitute for temperature control loops and should be explored as a means of reducing steam use — and saving dollars — on tracing systems.

Look for more information.

The economics of steam and steam savings are further dealt with in the case history section. Hopefully, the total effect will be to make steam users aware of, or remind them of, the major opportunities that exist for energy and dollar savings through boiler efficiency, boiler heat recovery, insulation, reduction of steam requirements, flash steam and condensate recovery, preheating boiler makeup water with cooling water from welders, cooling towers, compressors, etc. . . . the list goes on and on.

The opportunities are there for the taking. There are no physical barriers. If the barrier to better steam usage is bureaucratic or organizational — that is, if steam generation is the responsibility of the plant engineer or plant engineering department, and steam usage the responsibility of production departments . . . and the two cannot get together on the situation — sort it out. The savings will be worth the mild diplomacy (or head knocking) required.

Compressed air management

Over the past years, tremendous strides have been made in the development of advanced air operated devices and tools for a variety of industrial applications. But efficient as they are, these new tools cannot be viewed in isolation. They are part of an overall compressed air system within the plant — and are only as efficient as the power that drives them.

Yet in many plants, compressed air systems do not get the attention they deserve. These neglected systems waste compressed air, consume much more energy than is required, and cause air tool and hoist operators to take longer to do their jobs.

Compressed air is an obvious and very visible segment of your plant's operations to select as a priority for an energy conservation programme. It represents a valuable commodity whose use and efficiency can be relatively easily monitored and one which will show immediate and substantial savings in fuel bills as a result of enlightened energy conservation practices. In short, it's one of a number of good places to roll up sleeves and "start" on energy conservation once the basic housekeeping energy chores have been completed.

It is general practice in industry to express compressed air capacity as the flow at atmospheric pressure — the so-called "free air flow" — to avoid the burden of re-stating actual pressure for each application. But as any plant engineer who monitors his power bills knows, compressed air is anything but free.

And as the cost of energy continues to climb, compressed air will become an even more precious commodity.

For example, assuming a compressed air supply of 100 psig, at least one kilowatt of installed motive power is required to provide a "free" air flow of six cubic feet per minute. Assuming the cost of electricity at 2.5 cents per kilowatt-hour (Kwh), and a factory 48-hour week or 2,400 hours per year, the energy costs of compressing 1,000 cfm amount to more than $10,000 per year. This is a large-scale example; but in any plant if savings can be accomplished with little or no extra expenditure, even a ten percent reduction in energy use, due to improved efficiency of the system, can make a very worthwhile contribution to the company's "bottom line".

And as the flow and pressure of compressed air and the cost of energy increase, the savings become even more dramatic. As an eye opener, why not do a thumbnail analysis of your plant's compressed air consumption? Assuming an arbitrary level of energy reduction, the potential savings will probably surprise you.

Where can energy be saved?

There are a number of ways in which both compressed air and energy — and dollars — can be saved. They range from simple adjustments (for example, lowering the pressure in the plant system from an arbitrary or historic level to what is actually required to run equipment) . . . to basic maintenance such as repairing leaks in compressed air lines . . . to more costly steps such as replacing inefficient air compressors with newer models offering better fuel efficiency, improved air quality and greater overall savings.

For the sake of the analysis, the area can be divided into six components:

1. Selection of compressors.
2. Optimum compressor utilization.
3. Avoiding leaks and other wastage.
4. Efficient running of air driven equipment.
5. Lower pressure on the system.
6. Recovering the heat of compression.

These topic areas are not arranged in any order of priority based on the relative complexity or capital investment requirements to carry out the work. However, they are hopefully presented in a logical fashion that will enable the plant manager or anyone else responsible for compressed air to apply some basic ideas to reduction or energy consumption on industrial compressed air systems.

Certainly, before maximum use can be made of the information presented, the reader will have to understand the nature of his compressed air system and eventually carry out an "audit" of its efficiency. The subject of energy audits is covered fully in the introductory handbook in this series.

1) Selection of Compressors.

Most of the comments in the compressed air section apply to the operation of existing systems, but at the outset it is worth mentioning a number of factors which can be borne in mind when selecting a compressor or group of compressors for a new industrial application or replacement of an existing unit.

Prime among these, is the question of a large central installation versus several smaller separate compressors located nearer to the point of end use. What is best for a given plant will depend on the flow rate required, the physical layout of the plant, how the compressed air is used and the length of daily and weekly periods for which compressed air is used.

However, under the right conditions — and as a basic rule of thumb, 500 cfm appears to be a minimum flow level to derive real benefits — the use of smaller compressors each operating at a higher overall level of efficiency can offer significant benefits in energy and dollar savings, among them:

- unit selection in terms of size is less critical. Later modules can easily be added if budgets are tight. Less engineering and evaluation is often required to evaluate the plant's needs.
- initial capital cost is lower. In buying a single unit, there is often a tendency to "be conservative" and buy a unit which is really too big. A large compressor running "underloaded" much of the time is considerably less energy-efficient than a number of smaller machines running at their designed load.
- with multiple air cooled compressor units distributed throughout the plant, it may be easier and more economical to recover waste heat to take some of the load off plant heating units in the winter. (However, a large water cooled central unit could well improve the economics of recovery of coolant as water for washing operations or boiler feedwater.)

Certainly, each smaller compressor in each zone has to handle peak demands . . . and if the zone peaks don't coincide, a central installation where efficient use is made of the horsepower available may be preferable.

The selection of a type of compressor suited to the specific requirements of the plant can also have a significant effect on energy conservation. And one of the factors that should go into discussions with manufacturers is the potential for waste heat recovery from both air and water-cooled machines.

Multi-stage compression and other more esoteric machines can offer greater energy savings. While in many cases these machines entail a higher initial capital expenditure, an economic evaluation at the time of purchase may show that energy savings from one type of compressor are a critical factor in unit specification. As a basic rule: choose the compressor with the highest ratio of cfm delivered to brake horsepower.

2) Optimum Compressor Utilization.

Efficient operation of compressors is fundamental to the energy efficiency of the system. And the first step in the system involves the availability of suitable intake air for the compressor. Not surprisingly, cool clean dry intake air leads to more efficient compression and a sheltered inlet protected from rain on a

north wall is an ideal intake location — with ducting between the intake and compressor short, straight and of sufficient diameter. Dust in the system clogs filters and wastes energy.

As an indication of the savings that are possible by controlling intake air conditions, it is worth remembering that for every 10 inches of pressure lost at the inlet, compressor performance is reduced by two percent. Similarly, a 5°C rise in inlet temperature results in a 1 percent rise in energy consumption to achieve an equivalent output.

Compressor maintenance — a critical factor

Once it has been established that the compressor is receiving an air supply of sufficient quality, a critical factor becomes maintenance of the compressor itself. Perhaps the best advice that can be given here — although it seems obvious — is to follow the manufacturer's instructions to the letter. In the end, it will lead to maintained rated performance and optimum thermal efficiency.

Among the most critical items which should be checked are:

- tightness of driving belts.
- valve gear, pistons and piston rings on reciprocating compressors.
- vanes on rotary compressors.
- blades of turbo compressors.

The same principles apply to intercoolers and aftercoolers which reduce the amount of both oil moisture in compressed air. Here, it is critical that water cooling ducts are not scaled or blocked and regular draining provides an excellent opportunity to check and control this problem.

One additional means of increasing energy efficiency involves the use of generous sized receivers (larger than the usual 1-1.5 cf per 10 cfm). These can be a means of accommodating increased air requirements or high peak demands from an existing smaller compressor—with correspondingly low energy use. At points of sudden high demand in the system, an extra receiver near the point of take-off may avoid the need to provide extra capacity, and will save energy as a result. As a final step, a control system will help ensure efficiency of the compressor and thus its energy consumption. It can also assure that significant periods of off-load running do not occur and that an excessive number of stops and starts — both significant energy wasters — do not occur.

Basic instrumentation includes a pressure gauge on the receiver, water temperature gauges on the compressor cooling jacket and the aftercooler (in the case of water cooling) and air temperature gauges at the outlet of the compressor and in the receiver. Pressure gauges at selected points along the airline system will also indicate the effectiveness of the system and should be logged regularly along with other pertinent data to provide a record of efficiency.

While much can be done to upgrade energy efficiency without resorting to sophisticated control systems, the latter can offer significant savings — particularly by most efficiently balancing the load between compressors where two (lead and standby) or more are being used.

Keeping air dry can produce energy savings.

One of the parallels that exists between steam and compressed air operations is that both operate more efficiently without water in the distribution system.

With compressors, water enters as vapor along with air. In fact, under conditions of 24°C and 75 percent relative humidity, a 100 cfm compressor will take in about 18 gallons of water per day in the form of vapor. And about 90 percent of this water condenses during compression and winds up as a liquid in the aftercooler and piping system.

Water, or the sludge formed by the combination of compressor lube oil and water, corrodes the inside of air pipes, increasing internal resistance and building up a pressure drop that wastes power. The reduced air pressure reduces the efficiency of air tools. Just as importantly, corrosion pits and pockets can weaken the pipe and cause leakage at valves, joints and traps. Water in air systems can cause a multitude of other problems as well, but in general they all result in reduced productivity and energy efficiency.

The solution—refrigerated or chilled air dryers available from a number of manufacturers.

3) Avoiding leaks and other wastage.

The objective of a distribution system is to carry compressed air from the compressor to the tool or other powered equipment with the minimum pressure loss. And as a guide, a well laid out and maintained 100 psig system should deliver air to the point of use at close to 90 psig.

To make sure that the system is operating efficiently, it is imperative to record air pressure frequently during periods of heavy use—simultaneously listing pressures at the end of branches and at individual tools when they are running. Pressures recorded at the receiver and branch ends should not differ by more than 5-7 psig. If they do, chances are your company is wasting more in energy and production dollars than the cost of a revamping of the complete air system. And the effect on production of pressure loss is a dramatic and easily quantifiable one—a drop of 10 psig at the tool inlet reduces its available power by 14 percent. A drop of 30 psig can affect tool performance by as much as 55 percent—and drastically increase energy use per unit of production.

Branches, hoses, couplings—an opportunity area.

It is important to remember that the main air lines and associated branches, hoses, couplings and other accessories offer considerable opportunities for energy conservation. And among the ways to reduce pressure drop and leakage—and increase energy efficiency—are the following:

- use long radius bend and welded joints wherever possible in piping.
- incorporate strainers and lubricators for each air operated device.
- avoid condensed moisture buildup by sloping piping to strategically located drain legs equipped with automatically operated valves.

However, almost without exception, the largest single pressure loss in any compressed air system is found in the hose and its connection to the tool. For example, a system with 100 psig at the compressor receiver should produce 94-95 psig at the hose entrance—allowing for a 4-5 psig loss in the hose (proper hose selection can minimize that loss). A check with the manufacturer will assure that hoses are the right size and length to give proper throttle pressure and power at the equipment.

Pressure loss also frequently results from friction in piping. As a rule, the smaller and longer the pipe, the greater the friction. And shortening the length of pipe and reducing flow restrictions are both available remedies. The third major means of reducing pressure drop in the system is to reduce the velocity, or flow rate, of air through the system. For the main distribution line from the compressor installation, excessive energy loss can be avoided by restricting the air velocity to a maximum of 1,200 ft./min. Higher velocities are allowable in shorter branch lines of total lengths of less than 50 feet. Bear in mind, however, that reduction in velocity may entail installation of auxiliary receivers at points of heavy load.

Line loss through leakage can also represent a major energy—and dollar drain. Leaks occur frequently at air receiver relief valves, pipe and hose joints, shut-off valves, quick release couplings, tools and equipment. In extreme cases, compressed air leaks will account for 20 percent wastage in compressor capacity. Ten percent of capacity is commonplace.

Air leaks seem insignificant, and to be fair, they usually are caused by a large number of small openings. But the total effect adds up to a major energy loss, the solution to which problem can again be stated in one word—maintenance.

In this case, maintenance means regularly inspecting the steam packing valves in the system—repacking when necessary . . . replacing leaking shut-off valves and valves on equipment . . . in short, regularly inspecting lines for leaks and replacing faulty equipment. If your plant shuts down for Christmas or an annual holiday period, seize it as the ideal time to look for the small leaks that are almost impossible to hear over the noise of plant equipment. It's the time to carry out a blitz campaign—followed up by a year-round maintenance programme.

To make a ballpark estimate of the magnitude of the total line leaks before going ahead with a programme, one simple method is available which makes use of the known free air delivery capacity of the compressor and an ordinary watch.

With all air operated equipment shut off, run the air compressor until the system reaches full line

pressure and the compressor unloads, note the time. Due to air leaks, the system pressure will fall, and the compressor will come on load again, note the time. The period for which the compressor is on load and off load should be recorded at least four times to give a mean value of each.

Let T minutes = Time 'on load'
Let t minutes = Time 'off load'
Let Q = Delivered free air capacity of compressor in cubic feet/minute
Let L = Total system leakage in cubic feet free air per minute

$$L = \frac{Q \times T}{(T + t)} \text{ cfm}$$

Power wasted $\frac{L}{6}$ kW

Leaking air means leaking dollars (see chart in "Steam" section). So instead of a "hiss", try to think of the sound of rustling dollar bills — it may act as more of a motivator to put the system in good order.

4) Efficient running of air driven equipment.

Air powered equipment represents the final link in the air compression system and it goes without saying that unless pneumatic tools, directional control valves and cylinders and other equipment are supplied with properly conditioned compressed air, wear of seals and other moving parts will occur — leading inevitably to a loss in operating efficiency with possible leakage of compressed air and energy wastage.

Here, it is equally important that a properly planned maintenance programme be carried out — not only for the air operated equipment, but also for the "conditioning units", filters, pressure regulators and lubricators which service the tools and cylinders to keep the system operating at maximum efficiency and using the minimum amount of energy.

To remove pipe scale, water and compressor oil, which can combine to form highly abrasive compounds, filters should be located as close as possible to the equipment consuming the air. They should also be serviced regularly to clean or renew the elements which gradually become choked with dirt, causing excessive pressure drip and energy wastage.

The degree of filtration should be related to the application. The finer the pore size of the filter, the more dirt it will collect and the more readily it will become choked.

In the case of pneumatic instrumentation measuring equipment and other applications requiring extremely clean air, it may be necessary to consider ultra high efficiency filters to remove all traces of water and oil droplets. These specialized filters can easily cause excessive pressure drop if allowed to become choked with dirt, and it is advisable not only to protect against excessive dirt contamination by using pre-filters, but also to continuously monitor the pressure drop so that action can be taken when this pressure drop exceeds the maker's recommended level.

Equipment should also not be operated above its recommended operating pressure. This not only wastes energy, and leads to excessive wear with further energy wastage — it is dangerous.

In certain cases such as ejection nozzles, where air is discharged direct to atmosphere for the purposes of cleaning or cooling operation at high pressure not only causes excessive energy wastage — a ¼ in. nozzle at 100 psig, can waste energy at the rate of 15 Kw. The pressure to the nozzles should be reduced to a safe and economic level or in the case of cooling air fed by low pressure blowers or fans. Alternatively, devices converting a small flow of high pressure air into a large flow of low pressure air will soon pay for themselves on cooling or similar applications.

Careful attention should also be paid to the lubrication of pneumatic equipment by installing properly designed lubricating equipment and not depending upon an operator disconnecting a hose joint and injecting oil from a can.

The lubrication equipment should also be properly maintained and replenished with clean oil. In addition to reducing friction and thus reducing energy consumption, proper lubrication will prevent wear of seals and other rubbing parts and thus prevent energy wastage due to excessive air consumption or leakage.

The following is a suggested checklist:

- cracked or worn hoses — replace.
- cracked drain cocks — close (Ideally replace by automatic drains).
- hissing couplings, pipe joints, valves — service, reset or replace.

5) Using lower pressure.

Assuming that "housekeeping" has been carried out and leaks have been reduced to a minimum, careful thought should be given to using lower air pressures — both by operating equipment at lower than line pressure and, particularly, where the maximum pressure output of the compressor can actually be reduced.

As the chart shows, the latter case offers a very substantial potential for energy savings:

Single stage			
Pressure (psig)	100	90	80
Power reduction	—	−4%	−9%
Two stage water cooled			
Pressure (psig)	100	90	80
Power reduction	—	−4%	−11%
Two stage air cooled			
Pressure (psig)	100	90	80
Power reduction	—	−2.6%	−6.5%

In many plants, a great deal of pneumatic equipment (spray guns, cooling jets, hoists, control systems, etc.) are operating at higher pressures than those recommended by the manufacturer. As a result, considerable energy is being needlessly consumed. For example, where a pressure regulator can be fitted on a fluctuating main line supply of 85-105 psig and pressures reduced to the optimum 80 psig for a particular piece of equipment, a full 14% energy saving can be realized. A further decrease to 70 psig, results in nearly a 24 percent saving.

Double acting air cylinders are also used in considerable numbers, especially on automatic and automated production plants and machinery, etc. Often a number of cylinders are only required to exert full power in one direction, the other direction being a simple return non-working stroke. In these cases considerable savings can be obtained by using a reduced pressure for the return stroke action.

For example, operating at 80 psig, a double air cylinder will, in general, function equally well using 20 psig reduced pressure for the return stroke and will reduce consumption to something like 68 percent (32 percent saving per cycle).

Similarly, use of remote receiver tanks close to cyclical loads can significantly improve the efficiency of production tools and may permit a reduction in line pressure.

A further reduction to 50 percent can be obtained by discharging the exhaust from the high pressure working end of the cylinder to a low pressure supply for the return and for other uses. Here, the auxiliary port valve is operated in combination with the main control valve so that on the return stroke, the high pressure exhaust is first directed to the reservoir and, as pressures equalize, the auxiliary valve is then reversed giving final exhaust action through the main control valve in the normal manner.

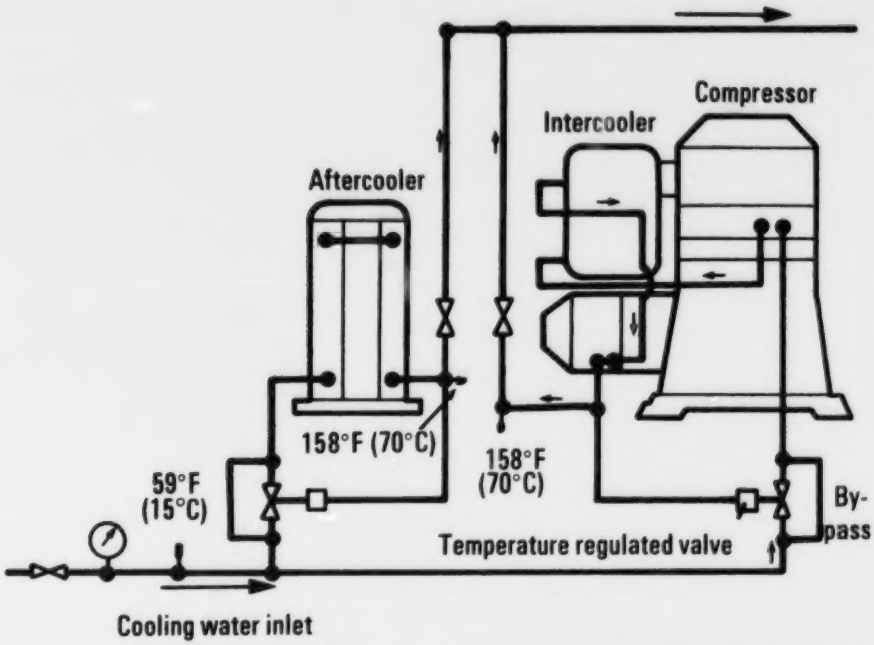
6) Recovering the heat of compression.

Since the energy used by a compressor is converted to heat, this is potentially the most rewarding area for energy savings. Practically all this energy can be made available for other purposes, and even a fractional percentage recovered represents a significant saving. Ideally, this should be considered when installing new equipment and discussions should be held with the compressor manufacturer at the time of selecting compression plant. However, there may be many existing points where hot air, water or oil — largely from various coolers — may be used.

In all standard air compressor installations, the major part of the energy put into the compressor by the electric motor is successfully re-extracted by compression stage cooling to maintain reasonable working temperatures by the intercooler to improve efficiency and by the aftercooler to remove moisture from the compressed air. The cooling medium is either water or air and the heat extracted is generally wasted.

For example, a 100 cfm compressor (26 hp) working at 100 psig can waste 65,000 Btu of heat per hour!

Frequently, compressors can be conveniently positioned to transport the heat to a location



A cooling water flow arrangement that offers good heat recovery and reduced cooling water consumption

where, for example, space heating is required. Temperatures of about 45°-70°C above ambient air in the case of cooling water and 9°-18°C in the case of cooling air, can generally be achieved. This is not always ideal for integrating with many heating systems, but the capital cost should always be balanced against the cost saving in space heating.

All compressor energy cannot be recovered, but with different arrangements, rather high efficiencies can be reached.

With water cooled compressors, most of the input energy can be recovered in the form of hot water and used for heating, as boiler feedwater, in wash and spray tanks and for other purposes.

With air cooled compressors, the hot air leaving the intercooler and the aftercooler can be ducted to an adjacent room and used for space heating, giving a recovery of up to 80 percent. To permit a constant room temperature also under varying compressor load, a recirculation flap valve should be used.

Summary:

Compressed air systems offer considerable potential for reduced energy consumption in most plant applications. As with the bulk of plant equipment, air compression must be seen as a *system*, and energy conservation activities approached in a systematic way.

The priorities of air management programmes in a given plant will depend on a host of local factors. But the necessity for a thorough, comprehensive approach — given the dollar savings that can be realized — do not.

Take a look at your compressed air system. Chances are, there's a good deal that can be done to improve its energy efficiency.

CASE HISTORIES

Air cooled compressor generates usable heat

The situation: Leigh Metal Products in London, Ontario were faced with replacing four smaller water cooled compressors which were both outdated and could not be counted on to deliver the full air capacity required for manufacturing.

Action taken: Given the choice of air and water cooled units, the company opted for a 40 h.p. screw-type compressor delivering 160-180 cfm. Leigh had already re-routed spot welder cooling water to the wash section of its metal preparation line and thus could make no use of compressor coolant from a water-cooled unit. They could, on the other hand, make use of the 100,000 or more Btu's/hr in heated air given off by the air-cooled compressor which, as it turned out, would be located next to the spray booth area — a cold spot in the plant and a continuing source of employee complaints. The compressor was installed and warm air ducted to the spray booth area during winter months and to atmosphere during the summer. The compressor was situated in a block wall enclosure to cut down on noise levels and to give better air control.

Energy savings: 100,000 + Btu/hr. In addition, cooling water consumption is eliminated.

Dollar savings: (Estimated) 100,000 Btu/hr × 2080 hrs/yr = 208 MMBtu/yr = 208 Mcf @ $2.00 = $516/year.

Cost of improvement: For ducting and labour $300.

Recommendation: Air-cooled compressor exhaust or heat from computer rooms should be considered a possible source of energy for space heating.

Automatic boiler tube cleaner conserves fuel

The situation: A container manufacturer realized that accumulation of soot on the surface of boiler tubes was acting as a thermal insulator and reducing the overall efficiency of the company's two boilers. The normal procedure had been to periodically (weekly or biweekly) shut down the boilers and manually clean each tube.

Action taken: The company implemented an automatic tube cleaning system in which each tube is cleaned at least every 30 minutes by adjustable timed blasts of compressed air. A catalyst is also automatically injected into the tube area to reduce soot and smoke emissions to the atmosphere.

Energy/dollar savings: This plant installed automatic tube cleaners on two fire tube boilers after year 2. One was rated at 400 hp (13.4 MBtu/hr), and the other at 500 hp (16.7 MBtu/hr). The following table shows actual fuel oil consumption and degree days for the year preceeding the installation and for two subsequent heating seasons.

Year	No. 6 Fuel Oil Consumption, gal.	Degree Day	Gal/ degree-d
1	373,062	4,147	89.96
Automatic tube cleaner installed			
2	349,773	4,196	83.36
3	327,712	3,942	83.13

For years 2 and 3 heating seasons, the
Average gal/degree-d
= (83.36 + 83.13)/2
= 83.25 gal/degree-d

Average percent savings in fuel with the automatic tube cleaner installed is:
Percent savings

$$= \frac{89.96 - 83.25}{89.96} \times 100\%$$

= 7.46%

Annual fuel savings
= 373,062 gal/yr × .0746
= 27,830 gal/year

Assuming the No. 6 fuel oil has a heating value of 152,000 Btu/U.S. gal;
Annual energy savings
= 152,000 Btu/gal × 27,830 gal/yr
= 4,230 MMBtu/yr

Based on a fuel oil cost of $0.30 per U.S. gallon;
Annual cost savings
= 27,830 gal/yr × 0.30 $/gal
= $8,350 per year

Installed equipment cost = $9,550.

In addition to the fuel cost savings of $8,350 per year, resulting from cleaner tubes, a substantial savings in the labour required to hand clean the tubes on a periodic basis (the 400 hp unit has 273 tubes and the 500 hp unit has 293 tubes) was realized.

Cost of Improvement: $9,550.

Recommendation: Look into automatic systems to keep boiler tubes clean and working efficiently. A fast check on the efficiency of the boiler can be made by installing a thermometer in the stack gas as close as possible to the last set of tubes. If the temperature of the gas exceeds the steam/water temperature by more than 38°C, fuel savings can be realized.

Boiler blowdown reduction through feedwater control

The situation: At Inco Limited's Stobie Mine complex the energy conservation committee was concerned that, to maintain desired dissolved and suspended solids concentration in the boiler water of the heating plant, 8 percent of the average output (including chemical treatment) was being blown out of the boiler. The boiler blowdown water contained considerable heat and thus represented a significant loss of energy. Studies indicated that with steady, automatic feedwater treatment control that this blowdown could be reduced by about 50 percent.

Existing feedwater chemical treatment consisted of batch-feeding of corrosion and scaling control chemicals to the three boilers producing a total of 150,000 lbs. per day of steam.

Action taken: A multi-functional liquid boiler treatment coupled with automatic controlled feeding equipment was installed at low cost.

Energy savings: With boiler blowdown reduced to about 4 percent, annual energy savings amount to 2,900 MMBtu's.

Dollar savings: 2,900 MMBtu's/year @ $2.00 /MMBtu's = $5,800./yr.

Cost of Improvement: $850.

Recommendation: Before planning steps to utilize boiler blowdown water, take any available steps to minimize blowdown. More effective treatment of boiler feedwater is one definite means to this end.

Boiler metering leads to consolidation, elimination

The situation: Over a period of 20 years at the main manufacturing facility of Griffith Laboratories in Scarborough, Ontario, five separate gas-fired boilers had been installed in various parts of the plant. Originally, provincial regulations had required that these package boilers be operated entirely independently of each other unless maintained by a stationary engineer. Gas consumption of the boilers had never been examined. Given higher energy costs and more recent regulations allowing the combination of similar boilers in a common header (with certain horsepower limits) without need for a stationary engineer, the firm decided to study its boiler efficiency.

Action taken: An individual gas meter was installed on each boiler and the following observations made: one older boiler was operating at 92% of capacity; three others were operating at 40% capacity or less; the fifth boiler was being kept active on a standby basis necessitating routine warmups, service and inspection.

Two steps were taken as a result:

1. The company found that internal costing procedures were not taking gas consumption of the older boiler into account—and the product served by this boiler was actually losing money. The manufacturing process was phased out, the product produced in a different way and the cost of a new boiler avoided.
2. Since studies showed only two boilers were needed. Two boilers were dismantled, sold, and the two remaining were hooked up with a common header with one operating at 90% of capacity and the other one standby for peak requirements.

Energy/dollar savings: Reduced gas consumption from operation of fewer boilers, estimated at $35,000. Additional savings are expected from maintenance, cooling and make-up water requirements, electrical requirements and heat recovery from flue gases.

Cost of improvement: $86,000.

Recommendation: Do not take operating efficiencies of boilers or other combustion equipment for granted. Substantial savings are available in this area. In the case of Griffith Laboratories, more than enough money was saved in one year from the phasing out of the old boiler and switch to a new manufacturing process to pay for the $1,000. per boiler cost of installing five individual gas meters.

Compressed air leak program saves energy

The situation: At the Hamilton, Ontario plant of International Harvester, leaks in compressed air lines were generally only repaired when they caused delays in production. 500 HP compressor, producing 2800 cfm.

Action taken: The company instituted a regular program to repair all leaks and continue to repair leaks as they occur. Air leaks totalling 1069 cfm (see chart below) were repaired during the initial crackdown.

Energy savings:

Hole Size	No. of Holes	Loss/Hole		Air Losses
1/64	2	× .244	=	.488 cfm
1/32	150	× .973	=	145.950 cfm
1/16	93	× 3.900	=	362.700 cfm
1/8	14	× 15.570	=	217.980 cfm
1/4	1	× 62.300	=	62.300 cfm
3/8	2	× 140.100	=	280.200 cfm
1/2	0	× 249.240	=	0 cfm
3/4	0	× 560.871	=	0 cfm
Total (All Leaks)				1069.618 cfm

Energy loss

$$1069.618\ \text{cfm} \times \frac{500\ \text{HP}}{2800\ \text{cfm}} \times \frac{.746\ \text{Kw}}{\text{HP}} \times \frac{3{,}413\ \text{BTU}}{\text{Kwh}} \times \frac{8760\ \text{Hr}}{\text{Year}}$$

= 4,260 MMBtu/year

Dollar savings:

Energy cost

$$1069.618\ \text{cfm} \times \left[\frac{500\ \text{HP}}{2800\ \text{cfm}} \times \frac{.746\ \text{Kw}}{\text{HP}} \times \frac{12\ \text{mos.}}{\text{Year}} \times \frac{\$3.60}{\text{Kw (demand)}} + 1069.618 \times \frac{500\ \text{HP}}{2800\ \text{cfm}} \times \frac{.746\ \text{Kw}}{\text{HP}} \times \frac{8760\ \text{Hrs.}}{\text{Year}} \times \frac{\$.0105}{\text{Kwh (cons'n)}} \right]$$

= $19,267.58/year

Cost of improvement:

Repair costs
245.6 Man-hours × $9.51/Man-hour + $350.34 Material = $2,686.00

Recommendation: Carry out a regular, compressed-air and/or steam leak repair program—it can be one of the best investments a company can make to conserve energy.

Compressed air maintenance eliminates compressor

The situation: At the Thorold, Ontario mill of the Ontario Paper Company, management were aware of a major energy saving and cost cutting opportunity in reducing leaks from the 95 psig compressed air system. The mill system consisted of three 1,400 cfm units powered by 300-hp motors and one 2,000 cfm machine with a 450-hp motor. Leaks were known to exist in the intercooler, on one compressor and in piping around the plant; however, given ambient noise levels, it was difficult to pinpoint and repair anything but the largest and most obvious leaks.

Action taken: Mill engineers took advantage of a period when the mill was "down" to implement a major programme of air leak tracing and repair. All leaks were located and marked during the down period and some repair work carried out. The remaining leaks were repaired as part of a longer term maintenance programme following start-up. The leaking intercooler was found to account for 30 percent of the air loss and was replaced.

Energy/dollar savings: After the programme, the company found it was able to eliminate the use of one of the 300-hp compressors—representing a saving of approximately $25,000/year in electrical energy.

Cost of improvement: Not available.

Recommendation: If necessary, look to a similar down period to put in motion an air leak repair

programme. After repairs have been made, it may be possible to eliminate compressors completely, as in the case of Ontario Paper, or possibly to cut the maximum output of a compressor. Both will result in substantial dollar savings for a small investment. (Ontario Paper calculated that a further reduction of 7.5% in horsepower used or $6,000/year could be achieved were it possible to lower main line air pressure to 80 psig.

Compressor cooling water used for boiler make-up

The situation: Management at 3M Canada Limited's London, Ontario plant some years ago saw the benefits in energy and water savings of a system which would collect compressor cooling water and use it, supplemented where necessary by city water, as boiler feedwater.

Action taken: Approximately 2.5 MM gal/yr of compressor cooling water is collected in a surge tank from the intercollers and aftercoolers of the plant's compressors. From here it is pumped into the boiler make-up system ahead of sodium zeolite softeners. During summer months, compressor cooling water volume is more than adequate for boiler make-up and enters the system at 38-43°C. During the winter, when higher steam demand leads to higher make-up demand, compressor cooling water must be supplemented by city water. In addition, winter-time city water temperatures are about 30°F cooler than summer temperatures—decreasing the volume of cooling water available for recovery.

Energy saved: Over the course of the year, the system saves the equivalent of 8,000 gal/yr of Bunker "C" and about 2.5 MM gal/yr of water.

Dollar savings:
Energy: 8,000 gal/yr @ $.35 gal
= $2,800/yr
Water: 2.5 MM gal/yr = 400,000 cf @
$.003/cf = $1,200/yr
Total = $4,000/year.

Cost of improvement: Using surplus equipment readily available in the plant, total cost of the installation was less than $500.

Recommendation: Look to cooling water from compressors, spot welders and other equipment as suitable pre-heated feedwater for boilers, wash/rinse cycles and other applications. Systems are usually simple and inexpensive to install and operate and yield an attractive return on investment based on both the waste heat recovered and the raw water conserved.

Contact pyrometer to detect faulty steam traps

The situation: Dominion Foundries and Steel Limited (DOFASCO) of Hamilton found that one of the most difficult facets of steam trap maintenance is the ability to locate traps which are faulty. Particular problems were encountered when many traps were piped to a common condensate tank.

Action taken: DOFASCO investigated the use of stethoscopes and an infrared camera to detect leaks, but found that the most reliable tool is the contact pyrometer. This is used to measure the surface temperature of the trap discharge piping. Depending on the type of trap and the steam conditions, DOFASCO has been able to develop a link between this exit temperature and the amount of leakage. This technique is now used in its trap maintenance programme.

Energy savings: Potential energy savings of about 10,000 lbs/hr of steam.

10,000 lbs/hr X 1300 Btu/lb X 8760 hrs/yr ÷ 0.8 (boiler efficiency) = 142,350 MMBtu/yr of fuel.

Dollar savings: 142,350 MMBtu/yr X $2.00/MMBtu = $284,700/yr. It is estimated that the cost of finding and repairing leaking steam traps could approach $20,000-$25,000, however the potential benefits are sufficient.
Net dollar savings = $260,000/yr.

Recommendation: Implement a comprehensive steam trap maintenance programme. Trap and steam conditions vary in each case, and extensive testing is required to determine the relationships between the exit temperatures and amount of leakage.

Direct steam injection can save energy

The situation: A plant has a demand for 30 gpm of water heated by steam from 15°C to 71°C for 4,000 hrs/yr. The traditional method using a heating coil and steam trap would involve a considerable loss in energy through the steam condensate return line. By the time condensate returned to the boiler it would have cooled to 49°C.

Action taken: The company utilized direct steam injection for heating the water, saving 14.5 Btu for each lb. of hot water produced (assuming 75% boiler efficiency).

Energy savings: 30 gpm X 8.34 lbs/gal X 60 mins/hr X 4,000 hrs/yr X 14.5 Btu/lb = 870 MMBtu/year.

Dollar savings: 870 MMBtu/yr = 870 Mcf/yr @ $2.00/Mcf = $1,740/year.

Cost of improvement: Not available; however, direct cost could be lower than for a comparable system involving steam coil and trap.

Recommendations: Consider the use of direct steam injection to heat water and aqueous solutions—you can save energy as well as installation and maintenance of heat exchangers, traps, and condensate returns. It should be borne in mind that if steam injection is used to heat an aqueous solution, allowance must be made for the diluting effect of the condensed steam. Extensive use of steam requires treatment and additional make-up water—a cost which should be factored into detailed calculations.

Factory compressed air replaced by pressure blower

The situation: At a General Motors plant, compressed air at 100 psig was used in the drying section of a detergent washing operation, used to remove moulding release fluid from instrument panels. As an inefficient use of factory air, it resulted in excessive energy consumption.

Action taken: A 30 horsepower pressure blower was installed to dry the parts. Compressed air service to the drying cycle was cut off.

Energy savings: Previous consumption: 1500 cfm X 9.5 Btu/cf^3 X 60 min/hr X 12 hr/day X 235 days/yr = 2411 MMBtu/yr.

Present consumption: 36 amps X 480 volts X $\frac{1\text{ Kw}}{1000\text{ watts}}$ X 235 $\frac{\text{day}}{\text{yr.}}$ X $\sqrt{3}$ X .8 (Power Factor) X 12 $\frac{\text{hrs}}{\text{day}}$ X 3413 $\frac{\text{Btu}}{\text{day}}$ = 230 MMBtu/yr.

Savings = 2411 - 230 = 2181 MMBtu/year.

Dollar savings:
2181 MMBtu = $\frac{2181\text{ MMBtu}}{3414}$ = 639,000 Kwh @ $.025 Kwh = $15,975/year.

Cost of improvement: $5,000 including equipment, ducting and labour.

Recommendation: Look for more economic localized energy alternatives to factory compressed air whenever this is possible.

Feedwater control keeps boiler tubes clean, saves Btu's

The situation: The prevention of scale formation, even on a boiler as small as 500 hp can produce energy savings of $30,000 per year or more—depending on the thickness and chemical composition of the scale.

Action taken: For a 500 hp boiler in use at its 100% rating of 16.[illegible] MMBtu/hr into steam, or approximately 16,[illegible]0 lb. steam/hr. At its rated 75% efficiency, and operating 8,000 hrs/yr:

Annual energy input
= 16.74 MMBtu/hr × 8000 hr/yr × 1/0.75
= 178,560 MMBtu.

Example A: if scale 1/32" thick is allowed to form on the tubes, and the tubes, and the scale is of "normal" composition (salts of Ca and Mg), reference to chart indicates an energy loss of 2%. Under these conditions,

Annual energy loss
= 178,560 MMBtu × 0.02.
= 3,570 MMBtu per year.
If the scale is cleaned out and prevented from reforming, and assuming the fuel oil used has a heating value of 144,000 Btu/US gal and costs 35¢ per gal., there will be a

Dollar saving
= 3,570 MMBtu × 1/0.144 MMBtu/gal × $0.35/gal.
= $8,680 per year.

Example B: If scale the same thickness forms, but of a composition high in iron and silica, a graph indicates an energy loss of 7%.

Annual energy loss
= 178,560 MMBtu × 0.07.
= 12,500 MMBtu per year.
Removing the scale and preventing its reforming with the same assumptions as to fuel oil:

Dollar saving
= 12,500 MMBtu × 1/0.144 MMBtu/gal × $0.35/gal.
= $30,400 per year.

Recommendation: Check boiler tubes visually for scale while the boiler is shut down for maintenance. Operating symptoms which may be due to scale include reduced steam output, excessive fuel use, and increased stack temperature.

If scale is present, consider modifying the feedwater treatment and/or the schedule of chemical additives. The cost of modification can vary widely, depending on such factors as the type of treatment facilities already available and the chemical problems present if any.

Heat transfer fluids used in tracing systems

The situation: An organic chemical plant became aware that substantial amounts of energy were needlessly being consumed by its 32,000 linear foot steam tracing system for process piping. The tracing system used plant steam capable of maintaining the heated product at 186°C while only 120°C was required.

Action taken: The company converted the steam tracing system to an ethylene glycol heat transfer system incorporating a shell and tube heat exchanger.

Energy savings: An average of 23.3 lb/hr of steam was consumed per 100 ft of line when using steam tracing. As little as 8 lb/hr depending on process conditions, was required to heat the fluid to 120°C in the heat transfer system.

Energy savings: Potential savings = (23.3 — 8.0) lb/100 ft/hr × 8,760 hr/yr × 32,000 ft = 42.9 MMlb/yr steam.
This amounts to a potential energy savings of about 43 billion Btu/yr although actual saving attained is approximately 30 billion Btu/yr because of losses due to process and ambient condition variation.

Dollar savings: 30,000 MMBtu = 30,000 Mcf @ $2.00/Mcf = $60,000/yr.

Cost of improvement: Not available; however, the cost of the shell and tube heat exchanger for heating the fluid is stated to be approximately equal to that of steam traps, check valves, thermostatic air vents, drains and fittings in a conventional steam tracing system.

Recommendation: Consider the possibility of converting steam tracing to another type of heating system. Potential savings are greatest when the required temperature in the process line is considerably less than that conveniently maintained by steam tracers. As a rule, the lower the process temperature, the greater the potential saving.

Major steam trap maintenance program exceeds conservation targets

The situation: Traditionally, management at the Maitland Works of Dupont of Canada in Sarnia were not particularly concerned about steam traps. They had always replaced those traps which seemed to be leaking and had run a few "blitz" programs in the fall of the year, but generally these usually yielded to "more important" maintenance activities.

The Works has a central Power House with six boilers and a steam generating capacity of 815 M pph. Steam at 250 and 450 psig is distributed to the various operating areas spread over approximately 100 acres. Average steam load through the year is 600 M lb/hr. A nominal steam cost of $1.90 per 1,000 pounds is used in any loss or savings estimates which follow.

However, in launching its Energy Conservation activities Dupont selected steam trap maintenance as a program which could get off to a fast start and yield results — providing initial momentum, while technical schemes to conserve energy were approved and implemented. In addition, expanded production indicated that the company would be hard pressed to meet production area steam demands in the next winter with the result that energy programs involving steam savings were most likely to receive the necessary resource support.

Following discussion with steam trap manufacturers, it was concluded that a conservative estimate of losses from steam trap failures was 15-30 M lbs/hr (2½-5% of average steam load) with an annual value of $250M-$500M. From these preliminary studies, it was also recognized that the probability of annual trap losses being greater than $1 MM was higher than that of their being less than $200 M. There appeared to be ample assurance that we could recover the estimated labour and material costs of $80 M to evaluate the program for one year.

From preliminary studies, it was concluded that an effective steam trap maintenance program appeared to have the potential of becoming the backbone of Dupont's energy conservation activities.

Action taken: Manpower was assigned on a full-time basis and those involved trained to become specialists in an on-going, year-round activity. Two mechanics were assigned full time, as well as an engineer to provide technical guidance on day-to-day activities and to develop solutions to major problems. A chemical operator was later added to the program when it was apparent the activity was paying off.

To focus on one area, recognizing that experiments and tests would be necessary to develop identification and data recording systems, the scope of the program was limited initially to one operating area, which involves 60-70% of the traps on the plant site.

An effective data recording system was considered essential. The company chose to follow the history of trap locations, rather than individual traps, as they suspected this approach would highlight the locations which presented especially difficult trapping problems. Goals were established for the program which were somewhat more optimistic than the "conservative" estimate of losses.

Short Term: — First year saving of $350 M — equivalent to 21M pph steam average through the year.
—Reduction in steam load of 42M pph by year end.

Long Term: — Generate the knowledge to achieve improved trap performance with less maintenance through:
—better traps
—correct sizing
—proper selection of trap for the job
—Develop improved trap selection and installation standards for new construction.

Procedures were as follows:
—Tagging each trap location with a numbered stainless steel band wired to inlet piping.
—Recording information including:
—type and size of trap installed
—installation arrangement — vertical or horizontal, open or closed discharge, existence of strainers and isolating valves.
—Testing traps:
—used stethoscope (96% disc traps); planned to evaluate an ultrasonic detector.
—a pyrometer was used as backup for specific types of traps.
—pressure profiles were plotted in condensate systems where there is evidence that back pressure was causing trap failure.
—Criteria for defective disc trap:
—Passing steam continuously; "machine gunning" — cycle time <4 secs. on ½" disc trap or <3 secs on ⅜" disc trap. This standard was considered tentative and will likely change when we generate the information necessary to base it on an ecomomic analysis.
—Defective traps were replaced where they could be isolated without affecting the process and maintain a record of trap replacement for revising the master records and for estimating steam savings.
—Correct obvious oversizing:
—½" disc traps or tracers were automatically replaced with smaller sizes when they failed; suspected oversizing of process traps were referred to the engineer for follow-up.
—Correct trap misapplication:
—Where the wrong type of trap had been used for a specific application, the trap was changed or the condition referred to the engineer.
—A report was issued and recommendations for follow-up by area maintenance crews made where significant piping alterations are involved and where major process shutdown or steam outage is required.
—In addition, an experimental program, a test program, was set up to evaluate a variety of traps in different applications. In time the results of this program will be used in developing standards.
—Traps were evaluated on a test apparatus to

determine performance characteristics and steam losses under varying pressure conditions.

Energy savings:
—Average steam saving first year — 20.5M pph net vs Target 21M pph
—Steam load reduction at year end — 50.4 M pph net vs Target 42M pph
—Reduction in prime fuel for steam generation due to steam trap maintenance, approximately 35,000 bbl oil.

Recommendation: Implement a steam trap maintenance program, but do not look for immediate results. In the first few months, the cumulative savings may not exceed the precision of the metering instruments. However, as long as defective traps are being replaced with good ones, you can be confident that you are saving steam. In Dupont's current program:
—has expanded trap maintenance to the entire site — now have three mechanics and one operator working full time to service 5,000 traps.
—Has completed three cycles in the area where the program was started and trap defect level is down from 33% to 7%.
—Average steam load is down 105 M lbs/hr (17.5%), compared with the corresponding period before the program, while production volume is down 0.2%. The saving is not all attributed to the steam trap program, as many othe activities are going on to reduce our energy consumption, but trap maintenance has certainly been a significant contributor. Cumulative value of the steam saving to date this year is $1.6MM.
—The company is beginning the process of removing many disc traps on the basis of information generated by the field testing program. The long term goal is to have a trap in each location that gives optimum equipment performance with minimum loss and maximum service life.

Then Dupont program has established that at least 70% steam losses from defective traps can be recovered through an ongoing maintenance program. Aside from the economic benefits, increased equipment capacity, prevention of equipment damage and improved equipment operation and process control could probably justify a steam trap maintenance program on their own.

Outdoor steam condensate tank insulated

The situation: A large steam condensate receiver tank (8 ft. diameter × 14 ft. in length — 452 sq. ft. area) at the Leamington plant of H. J. Heinz Limited was not insulated and was losing substantial amounts of heat to the atmosphere. Given the inability to economically move the tank inside and an average yearly thermal differential (condensate temperature less outdoor temperature) of 140°F (60°C), the company felt that some form of insulation was necessary.

Action taken: Fibreglass insulation was added to the tank by a contractor.

Energy savings: Average differential heat loss for the insulation is based on:

2.1 Btu/sq. ft/hour/1°F temperature difference.
Savings: $2.1 \times 452 \times 140 = 132{,}888$ Btu/hr.
$= \frac{132{,}888 \times 24 \times 365}{1000} = 1{,}164{,}030$ cf/yr.

Dollar savings: 1,164,030 cf/yr = 1,164 Mcf/yr @ $2.00 Mcf = $2,328/year.

Cost of improvement: $2,600 yielding a dcf rate of return of more than 50 percent.

Recommendation: Estimates of heat loss range down to 1 Btu/sq. ft./°F, but if internal space requirements or other factors preclude moving heated process, condensate or other tanks (which require heating to prevent freezing) indoors, carefully consider insulation. At the same time, make sure that condensate return lines are properly insulated. Heinz has also insulated two steam condensate tanks located inside the plant. While dollar savings here were not quite as dramatic, the installation was ecnomically justifiable on the strength of energy savings.

Paint system heat recovery uses steam flash tank

The situation: John Deere Limited, Welland works several years ago seized on an opportunity to improve the energy efficiency of its paint sytem by fully exploiting steam usage potential.

Action taken: A flash tank was installed to capture low pressure (100 psig) flash steam from the hot condensate from high pressure steam traps. All condensate from the steam coils in the washer, dryer and bake ovens are released to the flash tank at 2 psig with 13 percent of the condensate flashing into steam. This flash steam is absorbed in the washer tank at 160°F — providing heat and high temperature makeup for the washing stage. A float regulated valve drains part of the condensate from the flash tank into the washer tank as high temperature make-up water — the balance is pumped back to the boiler. Installation was done during normal working hours with no interruption to the paint system, except the final piping connections which were done on a weekend.

Energy savings: Approximately 14,000 MMBtu/yr.

Dollar savings: Approximately $28,000/yr.

Cost of improvement: $4,500 (in 1967) with a cash payback of less than one year.

Recommendation: Investigate the use of flash steam from condensate collected in steam traps. These systems frequently pay for themselves in reduced energy bills in less than one year.

Reduction in steam pressure follows energy audit

The situation: A steam energy audit was carried out at the Kitchener, Ontario plant of B. F. Goodrich Limited in which plant requirements were compared with boiler house output. The energy co-ordinator at the plant made the steam survey listing all important elements about the steam system — size of line, insulation status, pressures, position of steam traps, location and position of regulating stations, etc. Steam consumptions were measured or calculated.

Action taken: The survey of the steam system indicated that though no production equipment required more than 150 psig, boilers were producing 225 psig steam. As a result, an attempt was made to reduce boiler pressure to 150 psig in gradual steps (200 psig, 180 psig, etc.). At each step, feedback from production departments was solicited and no problems surfaced. At the 170 psig step, engineers found it difficult to control the boiler turbines due to lower pressure and a higher firing rate. The company now maintains steam pressure at a constant 180 psig and enjoys a good evaporation rate.

Energy savings: Due to the inability of segregating the effect of a number of energy conservation projects carried out at the same time, exact values are not known. However, given reduced boiler output, a higher steaming rate, reduced line heat losses and reduced pressure losses through leaks, malfunctioning traps, etc., energy savings are estimated at 5,770 MMBtu/year.

Dollar savings: 5,770 MMBtu/year = 5,570 Mcf/yr @ 2.00 Mcf = $11,140/year.

Cost of improvement: Time of plant personnel.

Recommendation: Examine the plant steam system with an eye to reducing pressures if possible; finding and fixing leaks and faulty traps — and revising the steam piping system to reduce unnecessary loops. Follow up with a similar investigation of the compresed air system.

Softened compressor cooling water as boiler make-up

The situation: Manufacturers recommendations to use softened water as the cooling medium in rotary screw compressors prompted the management of Libby, McNeill & Libby of Canada Limited to study a system whereby the softened compressor cooling water and its available heat could be recovered and used to advantage. Inlet temperature of water to the compressor had a mean temperature of approximately 7°C and a heat content of 13.06 Btu/lb. After compressor cooling, the 499.8 gph of water reached 91°C with a heat potential of 149.91 Btu/lb.

Action taken: The company installed piping and other necessary equipment to use the nearly 500 gpm of compressor cooling water as partial boiler feedwater make-up.

Energy savings: Heat available = 499.8 gal./hr X 8.3 lbs/gal = 4150 lbs/hr @ 150 Btu/lb. = 622,500 Btu/hr.
However, since the recovered cooling water was to be further utilized to cool condensate returns

from processir.g equipment, it was decided not to insulate the transmission line from the compressor to the main condensate vacuum pump. The net loss from this line amounts to 22,620/hr leaving a net gain of: 622,500 − 22,620 = 599,880 Btu/hr. Over a period of one year (8,000 hrs. operation): Heat conserved = 599,880 X 8,000 = 4.8 MMMBtu/yr. Water conserved = 499.8 X 8,000 = 3,998,400 gals/year.

Dollar savings: Heat: 4.8 MMMBtu = 4,800 Mcf @ $2.00/Mcf = $9,600/year.
Water: $3,233/year.
Total: $12,833/year.

Cost of improvement: $800.

Recommendation: Do not overlook compressor cooling water (and particularly *softened* cooling water) as a source of boilder feedwater. These recovery systems generally offer extremely high Dcf returns on investment and very attractive payback periods.

Steam generation uses incinerator flue gas

The situation: A manufacturer of asphalt roofing had been disposing of 16,000 cfm of asphalt saturated air by burning the mixture in an incinerator at 760°C. Incinerator exhaust was being discharged to the atmosphere while the company purchased 15,000 lb/hr of process steam at 150 psig from a neighbouring steam plant.

Action taken: Acting on the results of a brief study which showed that flue gases could be used to generate all the steam, and more, needed by the roofing plant, management installed a waste heat boiler in the incinerator stack — capitalizing at the same time on 200°F feedwater available elsewhere within the plant.

Energy savings: To produce one lb of 150 psig steam (186°C) from one lb of 94°C water requires 1026 Btu. Heat required to produce 15,000 lb steam = 1026 Btu/lb × 15000 lb/hr = 15.39 MMBtu/hr.
The flue gas flow rate at a gas density of .0763 lb/cf and standard conditions = 16,000 cfm × .0763 lb/cf × 60 min/hr = 73,248 lb/hr.
With a 2 per cent heat loss and Cp = 0.28 Btu/lb °F, the required temperature drop in the flue gas =

$$\frac{15.39 \text{ MMBtu/hr}}{0.28 \text{ Btu/lb°F} \times 73{,}248 \text{ lb/hr} \times (1 - 0.02)} = 766°\text{F}$$

This means that the flue gas need only be cooled to 1400-766 = 634°F to produce the required 15,000 lb/hr of 150 psig steam.

Dollar savings: Operating 3,000 hrs per year = 15,000 lb/hr × $1.00/Mlb × 3000 = $45,000 per/yr.
If flue gases were cooled to, say, 204°C, a total of 19,400 lb/hr of steam could have been generated with a total cost savings of more than $58,200/yr.

Cost of improvement: $37,000. Even at the lower steam output, payback was achieved in less than one year.

Recommendation: Check into plant exhaust streams with temperatures higher than 149°C as potential sources of heat for steam generation. Some thought should also be given to the potential for selling unneeded steam to a neighbouring plant. Note that cooling flue gas below 149°C can frequently bring corrosion problems caused by condensation of stack gas components.

Steam leaks repaired quickly

The situation: In some areas of Dominion Foundries and Steel Limited (DOFASCO) in Hamilton, steam leaks were repaired by shutting down the steam line in the area affected. This often posed scheduling problems, particularly in areas fed by only one steam line.

Action taken: One technique which has helped in the continuing battle against steam leaks is the use of an outside contractor with special equipment to fix steam leaks "live". This cuts down on the scheduling problems and thereby allows us to get leaks repaired more quickly than would be the case otherwise.

Energy savings: DOFASCO estimates that by using the on-line repair service, the yearly savings could approach an additional 1500 lbs/hr of steam.
1500 lbs/hr × 1300 Btu/lb × 8760 hrs/yr ÷ 0.8 (boiler efficiency) = 21,350 MMBtu/yr of fuel.

Dollar savings: 21,350 MMBtu/yr × $2.00/MMBtu = $42,700/yr.
The outside firm fixed 30 leaks during the year. Cost is estimated at $3,000-$5,000 to repair

these leaks using the specialist.
Net dollar savings — about $38,000/yr.

Recommendation: Consider a steam leak specialist. Use of a firm to repair leaks live on a contract basis has proved profitable for DOFASCO. This is a good way of fixing steam leaks — quickly.

Water spray reduces flash steam loss

The situation: At the Huntingdon, P.Q. plant of Cleyn and Tinker Limited, engineering staff realized that a significant amount of energy was being given up to the atmosphere through the loss of flash steam through a vent serving the 5-10 psi condensate return tank for the company's 125 psi steam system.

Action taken: Based on advice from another company, a simple spray system was set up in which 80 gph of demineralized water from treatment facilities (using just city water pressure) was sprayed into the tank through an atomizing nozzles at 10°C. The system reduced the loss of steam and latent heat through the vent to atmosphere to almost nil. At the same time, it provides 80 gpm of treated boiler feedwater preheated to 100°C (the temperature of condensate in the tank).

Energy savings: No detailed calculations have been carried out, but from basics: Heat recovered = 80 gph = 800 lb/hr X 24 hr/day X 6 day/wk X 50 wk/yr X (212 - 50)°F = .933 MMMBtu/year.

Dollar savings: .933 MMMBtu/yr = 5,060 gals/yr Bunker "C" @ .35/gal. = $1,771.17/year.
Water savings and savings in preheating amount to another $357.09/yr.
Total savings = $2,128.26/yr.

Recommendations: Look to demineralized spray systems to reduce flash steam losses—assuming the flash steam cannot be used for some other purpose more profitably. Cleyn and Tinker stress the importance of both a fine mist from the atomizer and an extremely fine screen to remove any suspended solids before water reaches the atomizing nozzle. Flash steam not only contains latent heat, it should be seen as pretreated feedwater. The cooling water would be required as feedwater anyway, but would have needed to be heated from city water temperature in the boiler.

Weekend compressed air reduction saves energy

The situation: At a General Motors plant, 100 psi air pressure service was maintained to all parts of the factory for 24 hours a day, all year round regardless of requirements.

Action taken: Plant air pressure was reduced to 40 psi—the lowest level allowable given the requirement for continual operation of paint pumps to stir metallic paint mixtures—on weekends and for periods of extended downtime.

Energy savings: Previous consumption: 15000 cfm X 9.5 Btu/cf^3 X 60 min/hr X 24 hrs/day X 365 days/yr. = 75,000 MMBtu/year.
Present consumption: = 56,000 MMBtu/year.
Saving: 75,000 - 56,000 = 19,000 MMBtu/year.

Dollar savings: 19,000 MMBtu/year = 5.6 MM Kwh/yr @ .025 Kwh = $140,000/year.

Cost of improvement: Nil.

Recommendation: Cut steam and compressed air pressure to the lowest possible levels during periods when the plant is "down". No investment is required to produce real energy savings.

Tips for saving money through steam and compressed air management

1. Fully insulate all steam and condensate lines, process equipment.
2. Cover, insulate condensate tanks.
3. Repair or replace faulty steam traps.
4. Repair all other sources of steam leakage including flanges and high pressure reducing stations.
5. Maintain steam jets used for vacuum system.
6. Assure boilers are operating at peak efficiency.
7. Keep boiler tube surfaces clean.
8. Return condensate to boiler — or use pre-softened cooling water from compressors, etc. as feedwater — to minimize both blowdown and overall energy and water consumption.
9. Monitor boiler blowdown chemical analysis.
10. Recapture blowdown energy using heat exchangers or flash tanks.
11. Use air heaters and / or economizers to recover heat from boiler flue gases.
12. Minimize the distance steam must travel by re-arranging process equipment, eliminating straggling steam laterals.
13. Use isolation valves to split up the steam distribution system.
14. Operate steam-heated processes at the lowest permissible temperature.
15. Lower steam pressures wherever possible.
16. Use steam traps and / or balanced pressure air vents to eliminate air films in steam lines.
17. Put flash steam to work in lower pressure applications.
18. Where clean condensate cannot be returned to the boiler, use it for washing or other processes.
19. Turn off steam tracing during mild weather.
20. Look to glycol tracing systems to replace steam.
21. Consider replacing electric motors with back pressure steam turbines and use exhaust steam for process heat.
22. Operate distillation columns at minimum quality requirements.
23. Operate distillation columns at near flooding conditions for maximum separation efficiency.
24. Determine correct feed plate location on distillation columns to increase efficiency and minimize steam consumption.
25. Consider switching selected steam stripping distillation units from direct (live) steam to indirect (dry) stripping.
26. Use correct size steam traps.
27. Evaluate replacing condensing steam turbine rotating equipment drives with electric motors, if your plant has a power generating capability.
28. Add traps to distillation column to reduce the reflux ratio.
29. Minimize boiler blowdown with better feedwater treatment.
30. Use waste heat low pressure steam for absorption refrigeration.
31. Replace barometric condensers with surface condensers.
32. Shut off steam traps on superheated steam lines when not in use.
33. Optimize operation of multi-stage vacuum steam jets.
34. Use optimum thickness insulation.
35. use reflux ratio control or similar control instead of flow control on distillation towers.
36. Substitute hot process fluids for steam.

Compressed air.

1. Make optimized selection of central compressor versus a number of smaller zone compressors.
2. Choose the compressor with the highest ratio of cfm delivered to brake horsepower.

3. Select an air intake location that provides dry, clean air.
4. Maintain compressor driving belts, and all other critical parts.
5. Ensure that water cooling ducts are not blocked.
6. Use larger or extra receivers on existing compressors.
7. Investigate automatic control systems.
8. Provide basic instrumentation to guage system efficiency.
9. Repair all line leaks promptly as part of a regular maintenance program.
10. Use long radius bend and welded joints wherever possible in piping.
11. Incorporate strainers and lubricators in each air-operated device.
12. Regularly maintain air operated equipment as well as "conditioning units" — filters, pressure regulators, and lubricators.
13. Do not operate equipment above manufacturer's recommended operating pressure.
14. Reduce air pressure to lowest feasible level.
15. Consider double acting air cylinders.
16. Use hot air from remote receiver tanks close to cylical loads.
17. Use hot air from air cooled compressors for space heating wherever economically vialble.
18. Cooling water from water cooled compressors has many potential uses within the plant.

Steam table (imperial units)

Gauge Pressure (psig)	Saturation or Boiling Temperature (Degrees F)	Specific Volume (Cu. Ft./Lb.)	Heat Content Above 32 Degrees F		
			Sensible Heat or Heat of Liquid (Btu/lb.)	Latent Heat or Heat of Evaporation (Btu/lb.)	Total Heat (Btu/lb.)
0	212.0	26.80	180.1	970.3	1150.4
1	215.5	25.13	183.6	968.1	1151.7
2	218.7	23.72	186.8	966.0	1152.8
3	221.7	22.47	189.8	964.1	1153.9
4	224.5	21.35	192.7	962.3	1155.0
5	227.3	20.34	195.5	960.5	1156.1
6	229.9	19.42	198.2	958.8	1157.0
7	232.4	18.58	200.7	957.2	1157.9
8	234.9	17.81	203.2	955.6	1158.8
9	237.2	17.11	205.6	954.1	1159.7
10	239.5	16.46	207.9	952.5	1160.4
11	241.7	15.86	210.1	951.1	1161.2
12	243.8	15.31	212.2	949.7	1161.9
13	245.9	14.79	214.3	948.3	1162.6
14	247.9	14.31	216.4	946.9	1163.2
15	249.8	13.86	218.3	945.6	1163.9
16	251.7	13.43	220.3	944.3	1164.6
17	253.6	13.03	222.2	943.0	1165.2
18	255.4	12.66	224.0	941.8	1165.8
19	257.1	12.31	225.7	940.6	1166.3
20	258.8	11.98	227.5	939.5	1167.0
21	260.5	11.67	229.2	938.3	1167.5
22	262.2	11.37	230.9	937.2	1168.1
23	263.8	11.08	232.5	936.1	1168.6
24	265.4	10.82	234.1	935.0	1169.1
25	266.9	10.56	235.6	934.0	1169.6
30	274.1	9.45	243.0	928.9	1171.9
35	280.7	8.56	249.8	924.2	1174.0
40	286.8	7.82	256.0	919.8	1175.8
45	292.4	7.20	261.8	915.7	1177.5
50	297.7	6.68	267.2	911.8	1179.0
55	302.7	6.23	272.4	908.1	1180.5
60	307.3	5.83	277.2	904.6	1181.8
65	311.8	5.49	281.8	901.3	1183.1
70	316.4	5.18	286.2	898.0	1184.2
75	320.1	4.91	290.4	894.8	1185.2
80	323.9	4.66	294.4	891.9	1186.3
85	327.6	4.44	298.2	899.0	1187.2
90	331.2	4.24	301.9	886.1	1188.0
95	334.6	4.06	305.5	883.3	1188.8
100	337.9	3.89	308.9	880.7	1189.6
105	341.1	3.74	312.3	878.1	1190.4
110	344.2	3.59	315.5	875.5	1191.0
115	347.2	3.46	318.7	873.0	1191.7
120	350.1	3.34	321.7	870.7	1192.4
125	352.9	3.23	324.7	868.3	1193.0
130	355.6	3.12	327.6	865.9	1193.5
135	358.3	3.02	330.4	863.7	1194.1
140	360.9	2.93	333.1	861.5	1194.6
145	363.4	2.84	335.8	859.3	1195.1
150	365.9	2.76	338.4	857.2	1195.6
155	368.3	2.68	340.9	855.0	1195.9
160	370.6	2.61	343.4	853.0	1196.4
165	372.9	2.54	345.9	850.9	1196.8
170	375.2	2.47	348.3	848.9	1197.2
175	377.4	2.41	350.7	846.9	1197.6
180	379.5	2.35	353.0	845.0	1198.0
185	381.6	2.30	355.2	843.1	1198.3
190	383.7	2.24	357.4	841.2	1198.6
195	385.8	2.19	359.6	839.2	1198.8
200	387.8	2.13	361.9	837.4	1199.3
210	391.7	2.04	366.0	833.8	1199.9
220	395.5	1.95	370.1	830.3	1200.4
230	399.1	1.88	374.1	826.8	1200.9
240	402.7	1.81	377.8	823.4	1201.3
250	406.1	1.74	381.6	820.1	1201.7
260	409.4	1.68	385.2	816.9	1202.1
270	412.6	1.62	388.7	813.7	1202.4
280	415.7	1.56	392.1	810.5	1202.7
290	418.8	1.52	395.5	807.5	1202.9
300	421.8	1.47	398.7	804.5	1203.2
400	448.2	1.12	428.1	776.4	1204.6
500	470.0	0.90	452.9	751.3	1204.3
600	488.8	0.75	474.6	728.3	1202.9

SI USAGE

Derived SI Units Having Special Names

Quantity	Unit	Formula	Symbol
Frequency	hertz	s^{-1}	Hz
Force	newton	$kg \cdot m/s^2$	N
Pressure or Stress	pascal	N/m^2	Pa
Energy or Work	joule	$N \cdot m$	J
Power	watt	J/s	W
Electric charge	coulomb	$A \cdot s$	C
Electric potential	volt	W/A	V
Electric resistance	ohm	V/A	Ω
Electric conductance	siemens	A/V	S
Electric capacitance	farad	C/V	F
Magnetic flux	weber	$V \cdot s$	Wb
Magnetic flux density	tesla	Wb/m^2	T
Inductance	henry	Wb/A	H
Luminous flux	lumen	$cd \cdot sr$	lm
Illuminance	lux	lm/m^2	lx

Common Equivalents and Conversions

Approximate Common Equivalents
1 in. = 25 mm
1 ft. = 0.30 m
1 yard = 0.91 m
1 mile = 1.6 km
1 sq. in. = 6.5 cm^2
1 sq. ft. = 0.09 m^2
1 sq. yd. = 0.84 m^2
1 acre = 0.40 ha
1 cu. in. = 16 cm^3
1 cu. ft. = 28 dm^3
1 cu. yd. = 0.76 m^3
1 quart (liq) = 1.1 ℓ
1 gallon = 4.5 ℓ
1 oz. (Avdp.) = 28 g
1 lb. (Avdp.) = 0.45 kg
1 hp (UK) = 0.746 kW
1 lbf. = 4.4 N
1 psi = 6.9 kPa

Some Other Derived SI Units

Quantity	Unit	Symbol
Area	square metre	m^2
Volume	cubic metre	m^3
Velocity-angular	radian per second	rad/s
Velocity-linear	metre per second	m/s
Acceleration-angular	radian per second squared	rad/s^2
Acceleration-linear	metre per second squared	m/s^2
Density (mass per unit volume)	kilogram per cubic metre	kg/m^3
Moment of force	newton metre	$N \cdot m$
Viscosity-dynamic	pascal second	$Pa \cdot s$
Thermal conductivity	watt per metre kelvin	$W/(m \cdot K)$
Thermal flux density, Irradiance	watt per square metre	W/m^2
Thermal capacity or Entropy	joule per kelvin	J/K
Permeability	henry per metre	H/m
Permittivity	farad per metre	F/m
Thermal resistance (R value)	square metre kelvin per watt	$m^2K \cdot w$
Energy density	joule per cubic metre	$J \cdot m^3$

SI PREFIXES

Multiplying Factor	Prefix	Symbol
1 000 000 000 000 000 000 = 10^{18}	exa	E
1 000 000 000 000 000 = 10^{15}	peta	P
1 000 000 000 000 = 10^{12}	tera	T
1 000 000 000 = 10^{9}	giga	G
1 000 000 = 10^{6}	mega	M
1 000 = 10^{3}	kilo	k
100 = 10^{2}	hecto	h
10 = 10^{1}	deca	da
0.1 = 10^{-1}	deci	d
0.01 = 10^{-2}	centi	c
0.001 = 10^{-3}	milli	m
0.000 001 = 10^{-6}	micro	μ
0.000 000 001 = 10^{-9}	nano	n
0.000 000 000 001 = 10^{-12}	pico	p
0.000 000 000 000 001 = 10^{-15}	femto	f
0.000 000 000 000 000 001 = 10^{-18}	atto	a

Some Non-SI Units Used with the SI

Unit	Symbol	Value in SI Units
minute	min	1 min = 60 s
hour	h	1 h = 3600 s
day	d	1 d = 86 400 s
degree (of arc)	°	$1^\circ = (\pi/180)$ rad
minute (of arc)	′	$1' = (\pi/10\,800)$ rad
second (of arc)	″	$1'' = (\pi/648\,000)$ rad
litre	l or ℓ	$1\ \ell = 1\ dm^3 = 10^{-3}\ m^3$
tonne	t	$1\ t = 10^3$ kg = 1000 kg
hectare	ha	1 ha = 10 000 m^2

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